Electricity Costing and Pricing Study

Volume I

Study Overview and Principal Policy Recommendations

October, 1976

The Minister of Energy has asked me to provide you with this complimentary copy.

Robert B. Taylor
Chairman

ELECTRICITY COSTING AND PRICING STUDY

VOLUME I
STUDY OVERVIEW AND PRINCIPAL POLICY RECOMMENDATIONS

Ontario Hydro
October 1976

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Robert B. Taylor, Chairman

22 October 1976

Honourable Dennis R. Timbrell,
Minister of Energy,
12th Floor,
56 Wellesley Street West,
Toronto, Ontario.

Dear Mr. Minister:

On behalf of the Board of Directors of Ontario Hydro, I hereby submit the report of the Electricity Costing & Pricing study team. In releasing this study for public hearings by the Ontario Energy Board, it would appear appropriate to review briefly those factors that influenced Ontario Hydro to initiate what has become one of the most exhaustive analyses of electricity costing and pricing that has ever been undertaken anywhere.

For several years Ontario Hydro has been concerned about the suitability of the pricing policies and practices within the electric system in Ontario to the changing environment and conditions of the 1970s. In April 1973, Task Force Hydro, in its reference to the principles of rate making, recommended that "Ontario Hydro adopt a pricing policy that will more accurately reflect the supply cost of electricity and that will give effect to government policies for the allocation of capital within the energy sector." The recommendation went on to say "Ontario Hydro's research programs aimed at developing a uniform costing philosophy based on marginal costing should be expanded to embrace studies of the feasibility and acceptability of: (a) bulk power and retail rates that vary with the time of day and season of year, (b) demand charges that are based on the customer's load at the time of the monthly or seasonal system peak rather than on his individual monthly peak." This recommendation provided an impetus to expand the research programs referred to.

Ontario Hydro

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26 October 197[illegible]

Honourable Dennis R. Timbrell,
Minister of Energy,
12th Floor,
56 Wellesley Street West,
Toronto, Ontario.

Dear Mr. Timbrell:

On behalf of the Board of Directors of Ontario Hydro, I formally submit the report of the Electricity Costing & Pricing Study team. In reviewing this study the [illegible] Ontario Energy Board, it would appear [illegible] relative [illegible] [illegible] Ontario [illegible] which has become one of the most [illegible] of electricity pricing [illegible] that has ever been [illegible].

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Honourable Dennis R. Timbrell 22October 1976

Ontario Hydro's submission (dated May, 1974) on bulk power rate proposals for 1975 included the following in the introductory statement: "Ontario Hydro, before these hearings started, committed itself to the making of an extensive study of its present cost allocation system with a view to assessing its merits as against the merits of other methods... Ontario Hydro intends to assess the appropriateness of this costing method by undertaking a major study which will investigate the feasibility of alternative techniques including marginal cost pricing." In its report, the Ontario Energy Board expressed its opinion as follows: "The Board is of the opinion that the matter of alternative cost allocations is worthy of the intensive study which Hydro has stated it will give to it."

In September 1974, Hydro's Board of Directors formally approved the expanded study and so informed the Minister of Energy who, in his response, welcomed Hydro's initiative.

The studies have been extensive and exhaustive and their completion and submission to the Minister of Energy at this time is several months beyond the original target. The Hydro Board has reviewed the study in summary form only and authorized its release with the following resolution:

"1. That the Board accepts the underlying principle that efficiency in the allocation and use of resources in producing electric energy is the appropriate objective for pricing electricity in Ontario.

2. That the report of the Electricity Costing and Pricing Study be submitted to the Minister of Energy for reference to the Ontario Energy Board for full public examination and review.

3. That the Board does not take any position at this time with respect to the conclusions and recommendations contained in the report and that the determination of appropriate action in connection with such conclusions and recommendations be subject to consideration by the Board in the light of the results of the public hearings."

Honourable Dennis R. Timbrell 22 October 1976

In emphasizing that it is taking no position on the study at the present time, the Board wants to make it perfectly clear that the whole purpose of the exercise from its inception has been to prepare a document that would serve as a useful focus of discussion concerning the development of an appropriate pricing structure for the electric power system in Ontario.

The full report is contained in 10 volumes, the first of which is a summary of the study. Copies will be available for distribution early in November. At that time it is Ontario Hydro's intention to provide copies to its bulk power customers and we will be glad to provide whatever additional copies your Ministry and the Ontario Energy Board require.

On behalf of the Board

Chairman

I. INTRODUCTION

From its beginning in the late 1880s until well past the mid-point of this century, electricity supply was an industry with declining costs. Generally, as the size of the utility increased, the unit cost of production and supply decreased. During the early years in Ontario, Sir Adam Beck demonstrated the advantages of abundant and reliable electric service by making low-cost electricity available to the people and industry of the province through expanding the system. The key was the downward cost-price spiral.

Until a few years ago, rate increases were few and far between. Electricity contributed to the growth and prosperity of Ontario. More recently, however, electric utility costs have gone up very rapidly; and they continue to rise. Rising interest rates, rising fuel costs, and the greater capital intensity of nuclear generation have been the primary factors in the increase in the cost of producing electricity.

Increasing costs of raw materials have led to increasing rates for electricity. The issue of electricity costs and prices has become a controversial and closely studied one. Few are indifferent to the costing and pricing policies of Ontario Hydro.

Besides the factor of increasing costs, there have been other social and political pressures. Environmentalists would like more social costs included in the price of electricity, in order to drive up prices and slow growth. Conservationists have called for zero energy growth and inverted rate structures. Others have suggested that prices should be used to redistribute wealth: low prices for the poor and high prices for the rich. Consumer spokesmen and industrialists would like to hold the line on prices, while others yet have suggested that Ontario Hydro's rate structure should do all these things.

Two factors, however, have come to loom larger than the others. They are availability of capital and the conservation of primary energy. While these problems are not new, they have become increasingly acute ones.

What does this mean for Ontario Hydro and the electric utility industry? It means an even closer scrutiny of costing and pricing-policies. But more than that, it means a greater concern with the basic resources (capital and primary energy) which Ontario Hydro, on behalf of its customers, requires of society. It means assessing the role that pricing can play to enhance the conservation of resources allocated to producing electricity.

Ontario Hydro has been aware of these concerns, and has undertaken to study them in a thorough review of its costing and pricing-policies. The purpose of this volume is to set forth the results of this study and its chief policy recommendations.

A. SCOPE OF ELECTRICITY COSTING AND PRICING STUDY

In a letter dated 15 October 1974, the Minister of Energy asked Ontario Hydro to identify all study areas recommended by the Ontario Energy Board or studies initiated internally, and to establish priorities for these studies with proposed completion dates. In a reply dated 20 November 1974, in commenting on studies relating to the costing and pricing of electricity, the Chairman of Ontario Hydro stated:

> *Hydro is undertaking a full scale study of this important subject with a scheduled completion date of February 1976. Following a review of the results by the Energy Board in 1976, we would propose to implement any changes January 1, 1977. This is a difficult study and because of its many facets the staff qualified for carrying it out are those most likely to be actively involved in annual rate hearings, long range planning hearings or other special hearings affecting costs and rates. As mentioned earlier, to assist in preparing these analyses we propose to use consultants where practicable to augment our own staff. Interim studies of certain aspects under this general heading, including a review of the demand/energy rate split, charges for non-common facilities and non-standard rates for such as interruptible service and furnace loads, should be available early next year.*

The undertakings mentioned above were entrusted to a steering-committee on electricity costing and pricing.

In general terms, the Steering-Committee's responsibilities were to initiate a review of Ontario Hydro's present costing and pricing-practices, and to recommend changes in policies and practices where warranted.

The Steering-Committee established four main areas of study; pricing, costing, demand elasticity, and impact, to be integrated into an overall study undertaken by a Project Team.

The full terms of reference for each study team will be found in Appendix II. What follows here is a brief outline of the purpose of each part of the study.

1. On Pricing

a. To make recommendations for the establishment and approval of corporate pricing-policies for the sale of electrical energy.

b. To make recommendations for the establishment and approval of rate structures and pricing practices, consistent with the afore-mentioned corporate policies for the sale of electrical energy to municipalities, retail system customers, and direct customers.

c. To make recommendations for the establishment of rate structures and pricing practices consistent with the afore-mentioned corporate policies for the resale of electrical energy by municipal utilities to their customers.

2. On Costing

a. To make recommendations for the establishment of appropriate principles and methods for determining electricity costs.

b. To make recommendations for the establishment and approval of appropriate principles and methods for allocating electricity costs to cost-of-power functions.

3. On Demand Elasticity

To provide interval estimates of the elasticity of demand for electricity in Ontario with respect to price and income, and of the cross-elasticities with respect to the price of alternative sources of energy.

4. On Impact

To assess the impact on customers, and on the economy of changes in the costing and pricing of electricity in Ontario.

B. APPROACH TO THE ISSUES

Essentially there are two main areas of costing and pricing policy on which the study focused, revenue requirement and pricing-objectives.

C. REVENUE REQUIREMENT

Ontario Hydro is a Crown corporation. The corporate purpose is found in Section 24, Subsection 2 (c) and Sections 58 and 84 of the Power Corporation Act. Briefly stated, it is "to generate and produce power in Ontario and to make it available for use through transformation, distribution, delivery and sale".

The corporate objective flowing out of the corporate purpose has been stated as follows:

> *To supply the demands of the people of Ontario for electrical energy at the lowest feasible cost consistent with safety for its employees and the public and a high quality of service to its customers, and subject to the social, economic, and environmental concerns of the people of Ontario.*

Ontario Hydro is a non-profit corporation. However, in any given year it must recover its costs. The revenue requirement reflects the accounting-costs of providing service in a given year, including net income to cover statutory debt-retirement provisions with any additional amounts needed to preserve financial soundness. Hence the revenue requirement determines the amount of money that must be obtained through rates. The procedures and principles for determining the revenue requirement are therefore an important element in the costing and pricing-process.

The analysis of the revenue requirement was undertaken in three segments: determination of the annual cost of power, allocation of costs to cost-of-power functions, and inflation accounting.

The results of this study are summarized in Section II.

D. PRICING-OBJECTIVE

The primary objective of any pricing-system is to generate enough revenue to meet the revenue requirement. However, there are many ways to design a rate structure to do that. If the pricing of electricity is to be soundly based, then it should start with a clear objective to guide the designing of the rate structure.

It is perhaps useful to consider briefly the development of pricing in the electric utility industry. At first, rates were based on a flat charge: so much a month for each light, each customer, each room, or each horsepower of connected motor load. This type of pricing was prompted largely by the lack of acceptable meters. With the wider use of metering, and as the art of ratesetting advanced, a new type of rate structure was introduced, consisting of a service charge plus a single price per kilowatt-hour, which ignored any relationship between cost and use. This eventually gave way to a more complex structure to reflect decreasing costs, in the form of a declining-block energy-rate structure. The minimum bill was also substituted for the service charge, mainly owing to customer objections to "paying something for nothing". Over time, the fixed charges were removed from the end rate and included only in the initial blocks. The end rate then covered only the average variable costs (plus some incremental distribution costs), which led to increased consumption. This declining-block rate structure has been described in some of the earlier literature, and much more so recently, as "promotional".

It is important to note that throughout this development, the two concepts that persisted were that the rates had to be related to current costs, and they had to treat customers fairly.

Writing in 1941, Dr Thomas H. Hogg, a former chairman of Ontario Hydro, stated:

> *Today the promotional rate structure is widely accepted among rate authorities . . . but thirty years ago it was a bold departure from custom; its results were uncertain . . . .*
>
> *The basic idea behind the promotional structure is this: the greater the load density on an electric distribution system, the greater the economy of operation and use of materials; the larger the demand for power, the greater the opportunity of developing large power resources and the greater the economies which come from large-scale generation. These factors lower the cost of power to consumers.*
>
> *The promotional rate has played an important part in enabling the Commission to break the circle of high price and low consumption . . . . The Commission tied power charges to costs and kept costs low. It cut rates at every opportunity, consistent with maintaining a sound financial position. The demand for electricity was found to increase rapidly as its price was reduced.*[1]

While Dr Hogg's statement was presented from the perspective of the 1940s, it is interesting to note how he perceived the sensitivity of demand for electricity to price. There have been many changes in pricing-policy over the years. However, economies of scale and the declining block energy-rate structure have been the keystones of pricing until recent years.

Inflation, conservation, and social and environmental considerations, in particular, have been responsible for many rate-structure proposals in recent years. All administratively practical pricing-alternatives received serious consideration in this study.

The chief pricing-objectives which the study team considered were fairness, redistribution of wealth, conservation, environmental protection, and economic efficiency. There is at least one alternative rate structure which would meet each of these objectives, and for some there are several. Furthermore, pricing-objectives are not necessarily mutually exclusive. The alternative pricing-objectives may be briefly outlined as follows:

1. Fairness

This requires an approach to pricing which the users of electricity and other interested parties consider fair. Fairness is one pricing-objective that has natural appeal. There are several rate structures that meet this pricing-objective, one of which is considered to be the current rate structure. Any rate structure should meet the criteria of fairness on which there is general agreement in the community.

2. Redistribution of Wealth

It has been suggested that one object of pricing should be to achieve a fairer distribution of wealth. Under this pricing-objective, some form of 'ability-to-pay' scheme would have to be devised. This approach would introduce serious administrative problems, including the determination of need. Again, several rate structures and schemes have been suggested, among them lifeline rates, energy stamps, and an energy tax credit.

3. Conservation

Another object of pricing could be conservation. There were some difficulties in defining conservation. Generally, however, the conservation objective has been interpreted as meaning a rate of growth substantially lower than historical levels, such as

[1]Thomas Hogg's remarks on the promotional rate structure may be found in *The People's Power*, by Merrill Denison (1960), p. 103.

zero energy growth, or a reduction of future growth projections. The leading rate structure associated with conservation is the 'inverted' rate structure, with rates set to achieve the desired growth rate.

4. Environmental Protection

Protection of the environment is another possible object of pricing. To be fully effective, such a pricing-objective would entail the concept of 'shadow pricing'. That is, the price of electricity would be based not only on the internal costs Ontario Hydro faced, but also on external costs (not valued in the market) of producing electricity.

5. Efficiency

There are others who suggest that the primary object of pricing policy should be economic efficiency. The price structure would be designed to contribute to the efficient allocation of the resources devoted to producing electricity. In order to meet the objective of efficiency, prices should be based on marginal costs. That is, such a price structure would reflect the increased or reduced costs of producing electricity and delivering it to the customers that resulted from their decisions about using it.

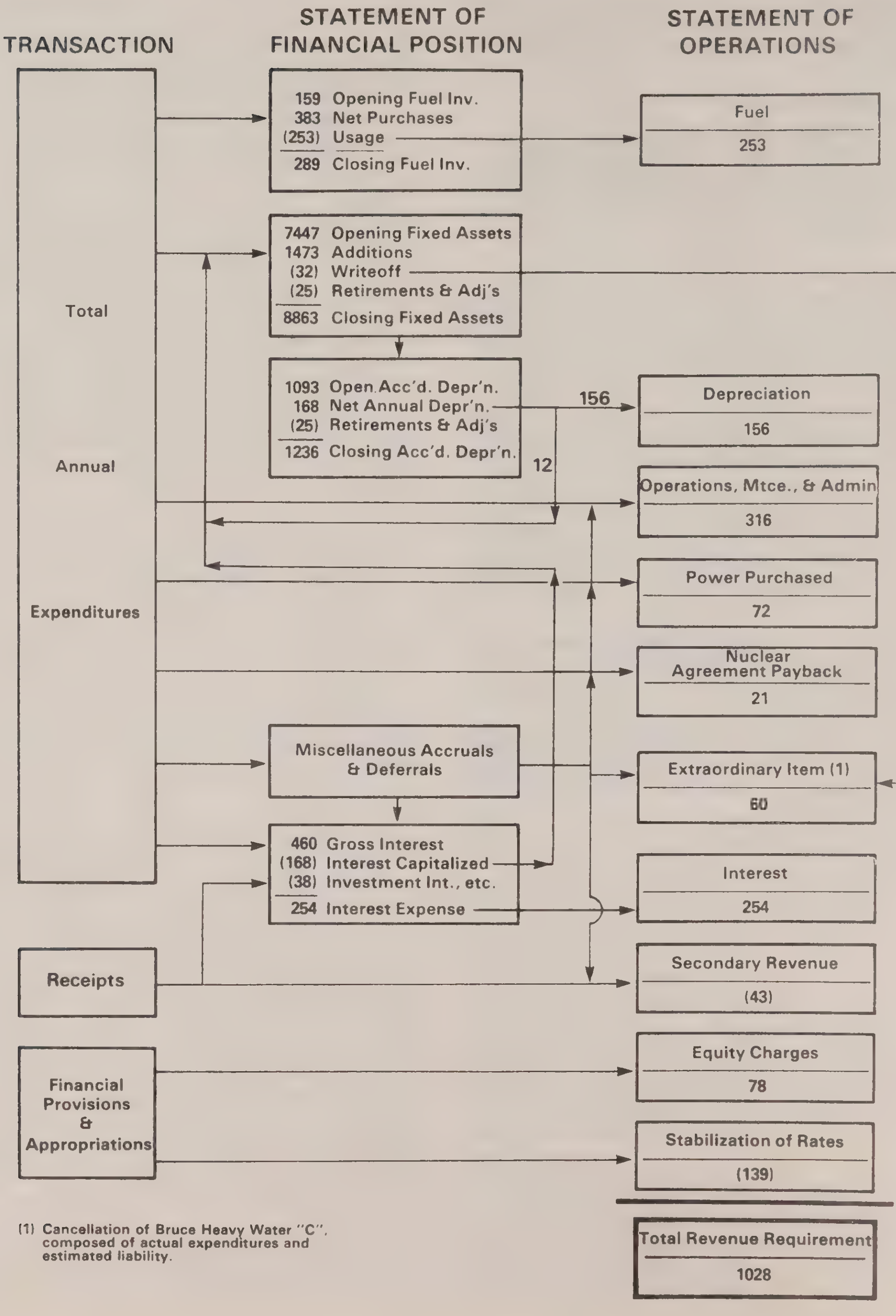
Sections III, IV, and V consider the alternative pricing-objective more closely. In Section III, "Demand Elasticity and Pricing", the sensitivity of the demand for electricity to price is considered. The issue is of importance in choosing the pricing-objective. In Section IV, the proposed pricing-objective and pricing-principles are set forth. Alternative pricing-objectives are discussed in Section V.

The proposed rate structure and illustrative rate schedules are provided in Section VI for both the bulk system and the municipal retail systems. Section VII outlines the pricing-proposals for interruptible power service.

The last section deals with the implications of the recommended changes in costing and pricing-policy. It briefly outlines what is involved in conducting an impact study, and summarizes the results of the impact analysis.

Figure 1

ONTARIO HYDRO
1975 ANNUAL COST OF POWER
MILLIONS OF DOLLARS



(1) Cancellation of Bruce Heavy Water "C", composed of actual expenditures and estimated liability.

II. THE REVENUE REQUIREMENT

The level of revenues necessary for Ontario Hydro to provide the resources to meet society's electricity demands is referred to as the revenue requirement. Ontario Hydro has an obligation to ensure that the level of the revenue requirement is appropriate. Revenues should neither be excessive nor fall short of covering annual operating-costs, including the net income needed to protect the financial soundness of the utility. Thus the principle is that the revenue requirement should fairly reflect the operating-costs for the given operating-year. The traditional accounting methods are therefore used to arrive at the revenue requirement.

The study team analysed three areas bearing on the determination of the revenue requirement:

1. Determining the annual cost of power,
2. Allocation of costs to cost-of-power functions, and
3. Inflation accounting.

A. DETERMINING THE ANNUAL COST OF POWER

The annual cost of power reflects historical costs: in other words, costs at the dollar value prevailing at the time of the transaction. Since these costs form the basis for the annual revenue requirement, they were examined to ensure that they are properly determined and are gathered in a manner suitable for allocation.

1. Division of Costs Between Current and Future Periods

Ontario Hydro's total annual expenditures are incurred for items related to the current production and supply of power, such as fuel, and for items required for the future production and supply of power, such as the construction of a new generating-station. To determine the annual cost of power, one must divide annual outlays between those that provide current benefits and those that provide future benefits. Furthermore, one must determine what share of outlays made in earlier years provides benefits to current customers.

2. Current-Period Costs

The cost of power for a given year consists of the sum of those costs classified as current, the share of the previously incurred costs deemed to benefit current customers (e.g., depreciation), and any charges for equity. The components are included in the Corporation's Statement of Operations, and may be shown graphically as in Figure 1. A discussion of each component is contained in the following pages.

3. Fuel Costs

Fuel costs for fossil-fired generation are charged to the cost of power on an average inventory basis. With coal, separate inventory accounts are maintained for stocks held in bulk storage. Shipments are made from the bulk-storage locations to the coal piles at individual stations, for which separate inventory accounts are also maintained. The transfers from bulk-storage coal inventory are charged at the average monthly inventory cost of coal, plus freight and storage charges. Average inventory costs are also calculated monthly for each station's coal inventory account. These average prices, which cover not only the bulk inventory costs but also any further freight costs, are used to calculate the cost of each type of coal consumed as reported by the station.

Oil is currently consumed only at one location, and is also costed on an average inventory basis.

Since natural gas feeds straight from the supplier's distribution system, Ontario Hydro does not store it, and no inventory accounts are required. Consumption is costed at the contract price.

For nuclear generation the charge to fuel expense is made at the average price of finished fuel inventory at the time the reactor is refuelled. Inventory accounts are maintained for uranium concentrate (raw material), refined uranium oxide (work in progress), and finished fuel. With the Nuclear Power Demonstration Generating Station, where the nuclear reactor is owned by Atomic Energy of Canada Limited (AECL), steam is purchased from AECL to operate Ontario Hydro-owned generators. The cost of the steam is treated as a fuel cost.

In determining the revenue requirement, average inventory cost is considered an appropriate method for Ontario Hydro to use for fuel costs, because it smooths the effect of price fluctuations, it is equally applicable in periods of inflation and deflation, and it is widely used by utilities and others.

The possibility of using a corporation-wide average for each type of coal is currently being examined. The use of an overall average would simplify the accounting-transactions, while matching the costing-procedures to those used in setting electricity rates.

4. Depreciation

Ontario Hydro's present depreciation policy is to distribute the original cost of capital facilities systematically over their estimated useful lives. The purpose is to recover cost. Through depreciation charges, funds become available for replacing assets and for other internal financing. Three separate procedures are currently used for depreciating major fixed assets, which comprise approximately 98 per cent of Ontario Hydro's total fixed assets in service. These are

1. the straight-line average-service-life procedure,
2. the straight-line remaining-service-life procedure, and
3. the sinking-fund procedure.

All assets placed in service in 1971 or after use the straight-line average-service-life procedure. All major fixed assets in service before 1971 receive a different treatment. Fossil and nuclear electric generating-stations are depreciated through the straight-line remaining-service-life-procedure, while for the other assets the sinking-fund procedure is used.

An overall assessment of Ontario Hydro's present policy and procedures for depreciating major fixed assets has been completed by the Finance Branch. The results of the study are contained in a report dated June 1975, and the associated recommendations were approved by the Board of Directors and will be implemented on 1 January 1977.

The report recommends viewing depreciation as a pure item of cost, which attempts to reflect the actual benefit provided to customers by assets in service.

A straight-line basis of depreciation for all major assets was recommended because engineering-studies showed that the usefulness of, or benefit provided by, all classes of major fixed assets could follow unpredictable patterns over their lives, and that the most rational approach was to assume that benefit was provided uniformly throughout the life of the assets. It was further concluded that accurate forecasts of salvage recoveries, re-

moval costs, or decommissioning-costs are currently not possible, but that when such costs are identifiable and estimable with some degree of confidence, they should be recognized when establishing asset service costs.

Three bases for depreciation have been recommended: the group basis; the property basis; and a combination of the two, which defines small groups of assets by location. This recommendation has been made possible by computerizing the depreciation processes.

The proposed more detailed allocation of depreciation on the basis of smaller groups defined by location, making possible property-level identification of net asset values and depreciation charges, will permit implementing recommendations about non-common cost-of-power functions.

The location-level identification will also facilitate setting net book values for specific assets being sold, as well as being compatible with the reporting-requirements of cost centres.

5. Operation, Maintenance, and Administration (OM&A)

The Operation, Maintenance, and Administration (OM&A) component of the Statement of Operations includes

1. The annual costs of operating, maintaining, and administering the power system,
2. Grants in lieu of property taxes, and
3. Water Rentals.

The treatment of the OM&A components can be summarized as follows:

a. Operations

Charged totally to the cost of power.

b. Maintenance

Routine maintenance is charged to the cost of power. If, however, the outlay is substantial and the maintenance results in increased efficiency, usefulness, capacity, or life of a physical asset, the charge is to capital. Repairs to physical assets that maintain a satisfactory operating-condition and do not extend the life of the asset are charged to the cost of power.

c. Administration

To some extent, these costs can be specifically identified as pertaining to capital or as current costs. Where a distinction is not possible, the division between the cost of power and capital is presently reached through procedures described in the following section on overheads.

Overheads are defined as the cost of administrative activities and supporting services which are not identifiable with the operation, maintenance, or construction of specific physical assets. Overhead activities that contribute to the ongoing aspects of the business are charged to current operation. Overhead costs from constructing physical assets are charged to capital. Overheads are also related to costs recovered from outside parties.

Overheads relating to construction of assets cannot always be precisely identified, and the division of overhead costs between capital work and current operations is reached by classifying the overheads involved with capital work into three categories:

1. *Category 1.* Expenses relating directly to construction activities, though not to specific assets, are capitalized at 100 per cent.
2. *Category 2.* Expenses having a capital content between 15 and 100 per cent are capitalized at a rate which is currently about 30 per cent.
3. *Category 3.* Expenses having a minor relationship with the Capital Construction Program (15 per cent at most) are capitalized at 10 per cent.

It is recognized that this process is not precise; but it is felt that the overheads capitalized are reasonably correct, and that added refinement would require extensive record-keeping. Several aspects of the current procedure are questionable, particularly the way that overheads capitalized are credited to current operating-accounts.

The Finance Branch is planning a study on overheads, which will include concerns that have been expressed about cost allocation. Because these concerns are in the nature of refinements, they are not expected to produce any changes that will greatly affect the level of costs or the allocation process.

d. Grants in Lieu of Taxes

For the most part, taxes and grants are assessed and paid in the current year. Where they are not, the share to be paid in the following year is estimated and accrued, so that the accounts properly represent the cost for that year.

e. Water Rentals

In the Statement of Operations water rents are included as an OM&A cost. These water rents are payments made under various water-power lease agreements with governmental or quasi-governmental organizations. Most of the payments are based on the net energy generated at the hydraulic generating-stations, and are calculated at rates established by the various long-term agreements. Water-rent payments are adjusted by an accrual system, so that the charges to the cost of power each year relate exactly to energy generated in that year.

An examination of the OM&A costs of the various organizational units revealed no serious problems. The only item of significance was the practice of charging for internal uses of electricity at rates that include equity charges. These equity charges correspond to the profits of a private firm, and it is not acceptable accounting-practice to realize profits on internal transactions. As a result of the investigations and a recommendation from the external auditors, corrections have been made.

6. Purchased Power

Purchased power consists of contracts negotiated on a long-term firm basis, and purchases of emergency power and energy to cover short-term deficiencies in Ontario Hydro resources.

Firm purchase agreements provide for specific quantities of power and/or energy to be delivered over specified periods of time. The cost of firm purchased power is based on rates set out in the contracts. For short-term purchases, the covering agreements make provision for arranging transactions on relatively short notice. Sometimes a reservation for a specific number of weeks is made a few weeks or months in advance. Other transactions are arranged on a day-to-day or hour-to-hour basis, when generation is not available or when the cost of the purchase is less than the least expensive generation available.

The rates for purchased power are determined by agreements and contracts. The quantities used are invoiced by the interconnected utilities at these rates, and the invoices are recorded in the fiscal year when the purchase was transacted. Because the power purchased is consumed in the current period, the total amount invoiced for purchased power for a fiscal period, with the cost of any special facilities that are required, is the correct cost for the period.

7. Nuclear Agreement Payback

Under an agreement between Ontario Hydro, Atomic Energy of Canada Limited, and the Province of Ontario, the three parties contributed to the capital costs of the first two units of the Pickering Generating-Station. The agreement requires Ontario Hydro to make payments termed 'payback' to AECL and the Province in proportion to their capital contributions. The payback represents the repayment of original capital cost based on operating-savings realized by running units 1 and 2 at Pickering rather than equivalent coal-fired units.

8. Interest

An important item in the total cost of power is interest. This consists of the cost of borrowed funds, reduced by income earned on investments and the amount of interest capitalized. The interest cost included in the cost of power is governed by financial policies and accounting-practices. These are outlined below.

a. Interest Expense

Interest expense consists of the interest on bonds, short-term notes, the purchase agreement for the heavy-water plant, and the lease-purchase agreement for the head-office building.

Interest on bonds and short-term notes is the annual cost of servicing the outstanding bonds and notes payable, and includes interest payments, amortization of bond discount, amortization of bond flotation expenses, and exchange.

Interest is paid to Atomic Energy of Canada Limited on the outstanding balance of debt arising from Ontario Hydro's agreement to purchase the Bruce Heavy-Water Plant from AECL. The amount of interest added to heavy-water production costs, and thus deferred to future operations, is presently determined by applying the rate of interest capitalization to the net book value of the plant.

b. Interest Earned

Interest earned consists of earnings from various investments, including short-term investment deposits in U.S. currency, as well as the minor items of miscellaneous interest income and expense. Investment income is calculated on an accrual basis, and includes amortization of premiums and discounts representing the differences between par value and purchased price of investment bonds.

c. Interest Capitalized

It is Ontario Hydro's general policy to capitalize the interest related to funds used for assets under construction, and to charge other interest to current operations. In this way, present customers are not required to pay the interest cost related to construction in progress which benefits future customers. This policy agrees with currently accepted practice among utilities. The interest to be capitalized each month is calculated by applying the established rate to the base of construction in progress. Interest is compounded annually, and ceases when an item is placed in service.

9. Secondary Sales

All sales of surplus interruptible power and associated energy to other power systems are classified as secondary sales. Although there are some sales to Canadian utilities, most sales by far are exports to the United States.

The annual revenue recorded for secondary sales is the total of the invoices rendered for the fiscal period. The costs associated with the revenue are not separated from the total costs of Ontario Hydro. Therefore fuel and other costs shown on the Statement of Operations include the costs of both primary and secondary sales.

10. Equity Financing and the Stabilization of Rates

Ontario Hydro acquires equity financing primarily from its customers through rates. It is Ontario Hydro's policy to include in the revenue requirement an equity charge high enough to maintain a sound financial position. The charge consists of the statutory debt-retirement charge and possible provisions to the Reserve for Stabilization of Rates and Contingencies.

The Power Corporation Act requires Hydro to charge to operations an annual amount which, together with interest at 4 per cent per annum, will retire debt over a 40-year period. That is the basis for the debt-retirement charge. An additional amount is included in rates, to raise the total equity charge high enough to satisfy Hydro's financial requirements, while giving consideration to the trade-offs between financial soundness, rate increases, availability of capital, and the capital construction program. At the end of the year, the required appropriation is recorded in the debt-retirement account and the realized provision or withdrawal is recorded in the Reserve for Stabilization of Rates and Contingencies. Surpluses or deficits reflecting the difference between planned and realized net income are not recorded. However, if the level of equity capital realized varies from that required, the difference should be a matter of consideration in determining revenue requirements in later years.

11. Future-Period Costs

a. Direct Charges to Capital

It is Ontario Hydro's policy to classify spending directly related to the purchase or construction of physical assets as capital. Charges for labour and materials related to capital construction projects are identified through the use of work-orders assigned to each capital project. As was mentioned earlier, interest and those overhead costs that can be specifically related to capital work are also added to the capital cost of each asset before its in-service date.

b. Indirect Charges to Capital

When directly allocating outlays for internal service functions is not practical, these expenditures are treated as overheads and allocated between current operations and capital in the manner discussed earlier in the section on overheads.

The charges to capital continue until an asset is placed in service. From then on, the cost of the asset is charged to the annual cost of power as depreciation.

12. Summary and Recommendations

In general, the methods Ontario Hydro uses to determine costs are appropriate. Costs for a year are reasonably related to the benefits received, and with the odd exception are suitably determined for cost allocation. A number of minor improvements were suggested as a result of the study, and some of these have

already been carried through. Others will be further considered as part of current or planned studies.

The recommendations may be summarized as follows:

1. *The planned overhead study should give full consideration to the following requirements for allocating the cost of power:*

a. *A more specific credit to the cost of power for operating, maintenance, and administrative costs capitalized as overhead.*

b. *A procedure for recoverable overheads that ensures credits are applied to the cost-of-power functions which absorbed the cost of the work.*

c. *The establishment of guidelines for calculating overheads included in internal transfers of costs for service functions.*

2. *When costs are distributed to accounts through a pre-determined distribution rate, any slight overabsorptions or underabsorptions should be incorporated into the following year's distribution rates. Where the effect on the cost of power or capital is great, an adjustment in the current year should be considered.*

The report on determining the annual cost of power is contained in Volume II.

B. ALLOCATION OF COSTS TO COST-OF-POWER FUNCTIONS

The operating-costs of Ontario Hydro are accumulated by organizational unit and type of expense for purposes of control and financial statement. These costs are then allocated to the various costing-categories according to cost allocation policies and procedures. The current cost-allocation policies are primarily based on study recommendations implemented in 1966. Specific procedures have been changed where required since then, but the underlying principles remain as defined in that study.

The policies and procedures for allocating costs to the costing-categories were reviewed in the current study, with emphasis on non-common and retail-distribution costs.

The object of the cost-allocation system is to allocate costs in a way that reflects how they are incurred. This requires the cost for any category to reflect the cost incurred in meeting the requirements of that category; it also requires supplying wholesale power at a similar cost for a similar type of service. This is achieved in a practical manner through a process of cost pooling. Costs are pooled according to the various functions the system performs.

1. Costing-Categories

The costing-categories, or functions to which costs are allocated, were reviewed in the study. It was considered that the following categories would be the most appropriate for allocating costs:

1. Bulk Power

This would consist of all costs required for serving customers at the bulk-power level. The common physical point of division between the facilities considered to provide all customers with power at the bulk level, and the facilities which do not accommodate everyone to the same extent and provide more of a specialized service, would be the high side of the 230-kilovolt and 115-kilovolt transformer stations which step power down to voltages below a nominal 115-kilovolt level. The 230-kilovolt and 115-kilovolt lines are considered to serve an integrated grid function for the benefit of all customers. The bulk-power function would include the cost of generation, transmission down to the 115-kilovolt level, transformation at the grid voltages, and the cost of providing equity for the wholesale system. It would be allocated to all customers at a rate based on their demand and energy use, with one small exception. The exception would be administrative costs that one could associate with any group of customers; these would be allocated to the applicable customers at a standard rate applied to their demand.

2. Metering

The cost of metering for billing-purposes would be contained in this function. Since metering is essential to the working of the system and all customers must be metered, the cost would be allocated to all customers, based on their demand.

3. Distribution

This function would contain the cost of all lines emanating from transformer stations at voltages less than 115 kilovolts which were not defined as specific facilities (see below). The cost of this function would be allocated to all customers, based on their demand. As a result of this allocation, there would be no benefits or disadvantages from the customers' geographic location relative to grid facilities.

4. Transformation I

This function would contain the cost of transforming from 115 kilovolts and over to levels above 20 kilovolts, except for specific-facility station costs. It would be allocated to all customers using the service, at a standard rate applied to their demand.

5. Transformation II

The cost of transforming from above 20 kilovolts to levels below 20 kilovolts, except for specific-facility station costs, would be contained in this function. The cost would be allocated to all customers using the service, at a standard rate applied to their demand.

6. Specific Facility

This function would contain the cost of all distribution and transformation facilities located within the customers' boundaries for their sole benefit, and which are not part of the bulk-power function. The cost would be allocated to customers having a specific facility, based on its original cost. The major premise in designing this allocation policy has been that either any distribution facility used specifically for a single customer and within its boundaries should be owned by the customer, or else the full cost of providing the facility should be recovered from the customer.

7. Return on Equity

Wholesale customers accumulate equity in Ontario Hydro through the debt-retirement charge. The equity of each customer reflects its contributions to the equity financing of Ontario Hydro, and the amount depends upon the size and age of the customer. A return is applied on the accumulated equity of each wholesale customer. The cost of providing this return is part of the common function, since all customers are considered to share equally in its benefits. Return on equity is being phased out over a period ending in 1978.

8. Retail Distribution

The costs of distributing power directly at the retail level to customers with lower demands than the large-user category are allocated to the retail-distribution function, and recovered through the retail rates.

2. Allocation of Operating-Costs to Costing-Categories

Various allocation methods are recommended for use in allocating operating-costs to the power-costing categories or functions, since there is no single method applicable to all situations. A summary of the allocation process is shown graphically in Figure 2.

A direct allocation is used when the costs can be directly related to a specific power-costing function. Examples are fuel, power purchased, the nuclear agreement payback, and secondary revenue, which are allocated to bulk power.

Where costs cannot be readily identified with a function, they can usually be identified with a class of asset. These are termed property classes, and are broad classifications, such as thermal generating-stations and high-voltage transmission lines. Where this mechanism is used, costs are first collected and allocated according to the property class to which they are related. Then the cost identified with each property class is pro-rated over the cost-of-power functions according to the functional use of the assets. Plant accounting-records provide the necessary data for this allocation, in the form of capital values of assets classified by property class and broken down by function. This allocation process forms an important part of the allocation of depreciation, interest, and operating, maintenance, and administrative costs.

Three cost items are allocated using other procedures. The cost of debt retirement is allocated between the bulk-power and the retail-distribution systems according to their debt and equity positions. The annual surplus or deficit is identified by customer group, and is transferred to the respective accounts in the Reserve for Stabilization of Rates and Contingencies. The amount required for crediting customers with return on equity is allocated to the bulk-power function.

3. Summary of Recommendations

The recommendations for cost allocation may be summarized as follows:

1. *For purposes of power costing, the point of division between the bulk-power function and other functions should be defined as the high side of the transformer stations which step power down to voltages below a nominal 115-kilovolt level.*

At present the division between grid and transformation stations is defined as 115 kilovolts. An estimated split is made between these when a station transforms from above 115 kilovolts to below 115 kilovolts, whereas the recommended method treats the whole station as a transformation function. The reason for the recommendation is that the high-voltage transformer station is the only physical point where facilities can be split between those that are common to all customers and those that are not.

2. *Except for specific administrative costs, the bulk-power function should be allocated on a uniform basis.*

At present the allocation of radial-line costs in this function makes an allowance for differences between loads and miles of line of customer classes. The recommendation would eliminate this, since facilities above the division point are considered to serve customers on a common basis, with their costs being shared equally.

3. *The full cost of metering should be identified as one function, and allocated on a uniform basis.*

Some metering-costs are now included in costs of Stage-Two transformation. These would be removed and pooled with other metering-costs. This would make it possible to identify meter costs fully and allocate them consistently.

4. *All lines emanating from transformer stations at voltages less than 115 kilovolts which are not defined as specific facilities should be considered to serve the distribution function.*

The low-voltage radial lines will be defined as distribution. The present radial-line cost pool includes costs for high and low-voltage lines. Since the low-voltage lines do not serve all customers to the same extent, they should not be considered a bulk-power cost.

5. *The costs of the distribution function should be allocated as a common cost to all customers.*

The allocation of these facilities would change from a kilowatt-per-mile basis to a kilowatt basis. This would eliminate the advantage or disadvantage of location with respect to grid facilities.

6. *The cost of transformation to below 115 kilovolts but above 20 kilovolts should comprise the cost of Stage-One transformation, and the costs of transformation to 20 kilovolts and below should comprise the cost of Stage-Two transformation.*

The dividing-point between the two levels of transformation cost is now at 10 kilovolts. The study group found that the 20-kilovolt level more correctly reflected the cost characteristics of the various levels of transformation.

7. *The cost of transformation losses associated with non-common facilities should be included in the charges for transformation.*

The cost of these losses would no longer be absorbed by all customers, based on levels of demand and energy. Including them in the transformation charges would ensure that allocated costs reflected the cost of service provided.

8. *Specific Facilities should be defined so as to include all distribution and transformation facilities which are located within customers' boundaries for their sole benefit, and do not form part of the bulk-power function.*

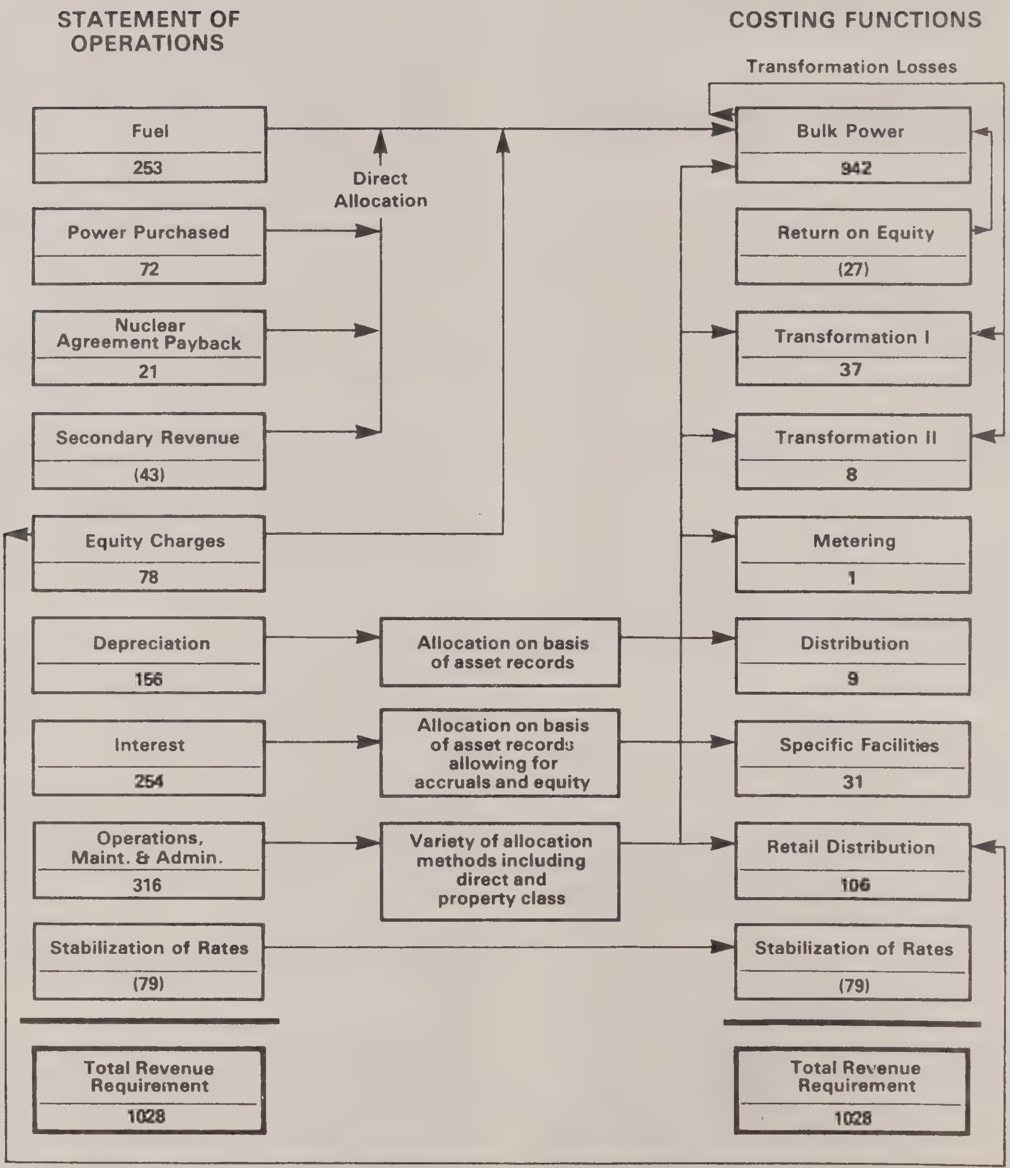
'Specific Facilities' would include transformation stations, whereas the function previously included only lines. Low-voltage lines and stations would thus be standarized in their treatment.

Ontario Hydro owns some of the low-voltage facilities in municipalities, and charges the municipality on the basis of the capital cost of the facility or on the basis of the kilowatts used through the facility. These facilities serve a distribution function, which is the responsibility of the municipalities. Ownership by the municipality provides operating-advantages for both parties. Moreover, the pooling-concept does not permit a precise reflection of the costs incurred for each individual facility.

Figure 2

PROPOSED COST OF POWER ALLOCATION PROCESS

MILLIONS OF DOLLARS
BASED ON 1975 COST OF POWER



9. ***Where it is practical, the allocation of administrative costs between the retail and wholesale systems should be based on statistical data pertinent to the costs being allocated.***

The study found that some administrative costs were being allocated on too general a basis. Specific recommendations have therefore been made to provide a more appropriate allocation of these costs.

10. ***The general wholesale administrative costs should be allocated amongst all wholesale functions.***

At present all the general wholesale administrative costs are allocated to the bulk-power function. Some of these costs are incurred by other functions, and should be reflected in the cost of those functions.

11. ***The interest allocation to costing-functions should recognize the equity contribution of the functions.***

All customers provide equity financing through the bulk-power function. This recommendation would ensure that the bulk-power function received credit for those contributions. The present practice has shared the credit for equity financing among all wholesale functions.

12. ***Equity charges should be allocated on the basis of the additional capital requirements of the wholesale and retail systems for the year.***

Since the main reason for equity charges is additional capital requirements, it is considered appropriate to allocate the equity charges on the basis of the respective requirements of the wholesale and retail systems. The current process does not fully recognize the requirements for equity financing of the two systems.

4. Effect of Proposed Allocation System on Customer Classes

Changes in costs allocated to customers as a result of the proposed allocation system were calculated on the basis of the 1975 cost of power. The calculations were made on the basis of the changes recommended for cost allocation only, and therefore do not reflect any of the other recommendations of the Electricity Costing and Pricing Study.

The effects of the proposed changes in the allocation system on customer class costs are shown in the accompanying table.

	1975 Cost of Power		
$ (Thousands)	Municipalities	Direct Industrial	Rural
Present method	653,918	120,734	253,041
Proposed method	650,681	117,794	259,218
Increase (Decrease)	(3,237)	(2,940)	6,177

The reports on the allocation of costs to cost-of-power functions are contained in Volume II.

C. INFLATION ACCOUNTING

One purpose of accounting is to provide periodic measurement of corporate progress and financial statements that help users make decisions. The traditional accounting-model is based on reporting transactions measured in terms of dollars at the date of those transactions, and hence does not reflect changes in the value of money.

The balance sheet is criticized on the grounds that fixed-asset values in particular do not represent the real value of those assets employed in a business. The income statement, it is claimed, reports illusory profits, because resources used up in generating revenues have to be replaced at higher cost. In effect, companies are paying income taxes and dividends on illusory profits, so that real equity is eroded.

In the search for solutions to the apparent deficiencies associated with traditional historical cost accounting, two main alternatives have emerged. One is a purchasing-power approach (general-price-level accounting), which involves applying a single index and is simply an extension of historical-cost accounting; the other is centred on current-value accounting, of which there are several techniques.

Both general-price-level and current-value accounting were assessed in terms of Ontario Hydro's specific needs, for both inside and outside purposes. The following briefly outlines the findings which form the basis for concluding that it would not be beneficial for Ontario Hydro to adopt any form of inflation accounting at this time:

1. Since Ontario Hydro pays neither income taxes nor dividends to shareholders, many valid reasons a private company might have for changing over simply do not apply to it.

2. Inflation is already recognized in the present process of financial planning, since future costs are adjusted for expected rates of inflation. In the financial forecast, overall cash-flow requirements are evaluated, giving consideration to trade-offs between financial soundness, rate increases, availability of capital, and the ongoing capital construction program. Adopting either form of inflation accounting would not benefit this process.

3. Adopting inflation accounting for purposes of internal reporting would not aid the processes of decision-making, control, and performance appraisal as presently carried out in Ontario Hydro.

   a. Spending-decisions are based on estimates of future incremental costs, which are not the same as costs restated by a general index or replacement costs. They are based on *differences* between alternatives, with future estimates of cash flows appropriately discounted, and the primary emphasis is on minimizing costs.

   b. Ontario Hydro's main management reporting-system is based on comparisons of actual and projected data against original forecast data on a compatible basis, and already includes predictions of cost escalation.

   c. Measures of productivity usually involve comparisons of work output against standards and service criteria, and any form of inflation accounting would not improve this process.

4. A portion of the equity financing obtained through rates is used to provide capital facilities to meet future load demand. Applying the techniques of current-value accounting, the argument that present customers should pay for the cost of facilities they are using in terms of today's dollars should be developed to further support total revenue requirements before reviewing bodies. This can be done without implementing a complete model of current-value accounting and producing the associated periodic statements.

5. For purposes of external reporting, it is considered prudent for Ontario Hydro to provide whatever information is required to maintain its standing in the Canadian and foreign capital markets. This will depend on the type of information investors need to improve their ability to analyse companies. In Canada, there are no immediate concerns or requirements to satisfy. In the U.S., the Securities and Exchange Commission (SEC) now requires registrants to provide certain current-value information. At present this requirement does not apply to foreign governments and agencies, but this may very well change in the future.

6. While academics, accountants, and businessmen have been wrestling with the problems of inflation accounting for some years, accounting-bodies are still undecided about the most appropriate inflation-accounting techniques. Initial efforts were directed mainly towards general-price-level accounting, whereas the primary focus now is on current-value accounting, and different countries are in different stages of development. In the United Kingdom, the proposals of a government-appointed Inflation Accounting Committee have been accepted, a steering-group is working on resolving the problems of implementing current-value accounting, and publication of a new standard is expected by the fall of 1977. As mentioned above, the SEC in the U.S. now requires registrants to provide certain current-value information. In Canada, the Canadian Institute of Chartered Accountants (CICA) is in the process of issuing a discussion paper on current-value accounting.

Summary of Recommendations

The recommendations can be summarized as follows:

1. *Ontario Hydro should not adopt inflation-accounting techniques for internal purposes at this time.*

2. *Ontario Hydro should not adopt inflation-accounting techniques for purposes of general external reporting at this time. However, a further study should be carried out to determine the cost and benefits associated with providing certain replacement-cost information required by the SEC in the U.S., but not yet mandatory for foreign governments and agencies.*

3. *Ontario Hydro should make its report on inflation accounting available to the CICA and other interested parties.*

The full report on inflation accounting forms the subject of Volume III.

III. DEMAND ELASTICITY AND PRICING

A. THE DEMAND FOR ELECTRICITY

In recent years there has been increasing interest and study of the demand for electricity in North America by regulators, intervenors, academics, and the utilities themselves. Generally, the factors which determine the demand for electricity may be grouped into five categories.

1. Price of Electricity

Prices are the key mechanisms or rationing-devices in an economy for determining the demand for a particular mix of goods and services, given aggregate consumption plans. The price of electricity is the most important factor affecting the demand for electricity over which the utility has control.

2. Price of Energy Substitutes and Complements

The price of other energy forms (e.g., natural gas and oil) which compete directly with electricity for the customer's dollar affects the demand for electricity. Sometimes 'substitutes' may be of little significance; for example, this could be so in the demand for electricity for lighting purposes. However, in other cases, substitutes do compete vigorously with electricity, particularly where fossil-fuel energy sources may be used directly to provide the same services as electricity, as (for example) in space-heating. Other factors, such as housing, or appliances used in conjunction with electricity, are said to be complements. An increase in the price of a complement will tend to reduce the demand for electricity, while an increase in the price of a substitute will tend to increase the demand.

3. General Economic Activity

The demand for electricity is affected by all measures of a customer's general economic activity, be the customer a business or an industry. Examples of such measures would be personal income, total output, and value added in manufacturing.

4. Customer Tastes And Attitudes

The preference pattern that customers show between using electricity and buying other goods and services also affects the demand for electricity. The preferences or tastes of an individual are influenced by several factors. For example, persons living in city apartments may have quite a different set of preferences for electricity from those living in single-family homes outside the city.

5. Other Factors

Other factors such as climate, geography, and population clearly affect the demand for electricity.

B. DEMAND FUNCTIONS AND DEMAND ELASTICITY

A full analysis of the demand for electricity is included in Volume IV.

The demand study concentrated on what is called the 'demand function' for electricity, which shows mathematically the relation between the amount of electricity demanded and one or more factors, such as price. However, the number of such influencing factors is great, and many are difficult to measure in numerical terms. They are also often interdependent.

From the point of view of a business, these various factors range from controllable to uncontrollable and from partly predictable to totally unpredictable. Any one business can control only a few, either wholly or in part. The electric utility industry can to some extent control the quality and price of the service. Furthermore, electric utilities can influence awareness and certain attitudinal factors through advertising and marketing. Ontario Hydro's conservation program is an example of this.

Of particular interest is the measure or coefficient of the sensitivity of demand for electrical energy to price. Such a measure is called the price elasticity of demand. Elasticity has a precise mathematical definition, but it can usually be characterized for small changes by the percentage change in quantity sold that a percentage change in the causal factor will bring about when all other influencing factors remain unchanged. Thus price elasticity of demand is the percentage change in volume demanded divided by a given percentage change in price, other factors held constant. For example, a price elasticity of -0.5 means that the amount demanded will fall by five per cent if the price rises by ten per cent.

If customers adjust their demand for electricity less than proportionately in response to a given percentage change in price, demand is said to be 'inelastic'. The ratio of percentage change in quantity over percentage change in price is then less than one (in absolute terms). If the resulting change is more than proportionate, then demand is said to be elastic; the ratio is larger than one (in absolute terms).

Other 'elasticities' or measures of responsiveness can be defined. 'Cross-elasticity' is similar to price elasticity. With this measure, however, the response in quantity demanded is caused by a given percentage change in the price of another good or service. Similarly, 'income elasticity' measures the response of demand for electricity to changes in household income or production output.

Given this background, one can assess the relevance of price elasticity of demand for electricity within the context of current policy considerations.

C. RELEVANCE OF PRICE ELASTICITY OF DEMAND FOR ELECTRICITY

Demand-elasticity measures have three main uses. The first is to assist short-run and long-run forecasting by estimating the effect on levels of demand of changing real prices, all else equal. A second is to measure the potential revenue changes expected from proposed price increases. Finally, one may use elasticities in designing rate structures, once costs have been determined.

Forecasting

Every business decision is based upon some kind of forecast, explicit or implicit. Generally the techniques employed can only be assessed in the context of the current state of the art and the accepted theory of estimating-techniques and forecasting-methods. These methods may range from the one extreme of simply extending a curve fitted to past trends, or polling customers or sales staff, to the other extreme of elaborate econometric or computer-simulation models. No technique suits all occasions.

Insofar as demand is sensitive to price, price elasticity of demand for electricity plays an important role, implicitly or explicitly, in a utility's long-range planning. This involves estimating how the sales and peak-load requirements of the utility will change, given expected changes in electricity prices, and what this growth implies for appropriate system planning. Virtually all the work which has been done so far on price elasticity is in this area. Furthermore, most work relates to growth in total kilowatt-hour sales, and not peak-period demand.

Revenue Impact

Demand elasticities can be used to assess the effect of proposed rate changes on revenues. In general, one would meas-

ure this by contrasting the revenues the current level of use would yield at proposed rates with the revenue stream an estimated future level of use would yield at those rates.

Rate-Structure Design

Price elasticity begins to play a formal part in designing rate structures with the development of marginal-cost and time-of-use pricing. Considerations of price elasticity bear to some degree on both determining costs and setting rates based upon those costs. However, insofar as rates are cost-based, demand elasticities play a limited role in rate-structure design. Any departure from cost-based rates increases the importance of demand elasticities for both prices and costs.

At present it would not be appropriate to apply available elasticity results to rate-structure design. No reliable estimates have been made of how time of use might affect the cross-elasticity of demand. This is mainly because time-of-use pricing is relatively new for North American utilities, and hence there are no data available for estimating time-of-use elasticities quantitatively.

D. PRICE ELASTICITY OF DEMAND FOR ELECTRICITY IN ONTARIO

The demand studies undertaken by Ontario Hydro were econometric.[2]
Essentially, the econometric approach consists of constructing numerical relationships between the demand for a good or service and the factors influencing the demand. Such a relationship may be called a demand function, or (more precisely) a statistical demand function.

The main demand model looked at the residential market for electricity. Among the variables examined were real income; the price of electricity itself; the price of substitute services, namely gas and oil; the stock of consumer durables; new housing; existing households, over time, serviced by gas (not serviced); new households, over time, serviced by gas (not serviced) and the ratio of single-family dwellings to total dwellings.

There has been considerable progress in demand analysis in the last decade; and while the conclusions are seldom new (for example, the short-run demand for electricity is inelastic to price, although not perfectly inelastic), the means used to arrive at those results are new. Analytical and quantitative techniques have been employed that would satisfy the standards set by professional econometricians. Therefore the results have an objectivity about them that may be more satisfactory than the subjective assessment used in the past. However, it must be observed, (in the words of the well-known econometrician D.B. Suits) that

> *The econometric model is not . . . a substitute for judgment, but rather it serves to focus attention on the factors about which judgment must be exercised.*

Furthermore, elasticity estimates derived from a model cannot replace the model itself. The measures are a convenient means of presenting, in summary form, conclusions derived from the model about the quantitative effect on demand of changes in different factors affecting demand.

The model employed to assess the residential demand for electricity performs fairly well when assessed on the basis of economic, theoretical, and statistical criteria such as

1. Statistical tests on results and
2. 'Tracking': that is, comparing forecast results with actual results.

Even given this relatively good performance, it is important to bear in mind that the model's coefficients are based upon the historical experience of joint variation in quantity, price, and the other factors affecting demand. There are restrictions in using the model to assess the impact of price changes. For example, if the maximum variation in historical price has been about ten per cent, then the model can be used with some confidence to assess the effect of price changes of ten per cent at most. Confidence in the answers the model gives will not be as great when it is used to assess the effects of larger percentage price changes.

It is important to note that the demand for electricity in the residential and industrial markets is not perfectly inelastic. The demand for electricity is sensitive to price. The distinction between long-run and short-run elasticities is based on the time duration of the response in quantity demanded to a given change in price. Short-run elasticities give a measure of the response of quantity demanded to the given price change in the short term, from one year to eighteen months. Long-run elasticities give a measure of the quantity demanded to the given price change over the longer term of from five to seven years. Most adjustment in quantity demanded to price charged would take place in this interval. Long-run elasticities are usually greater than short-run elasticities. This is because the customer can adjust both his stock of appliances and how intensely he uses them over the long run. In the short run, the customer can only adjust the intensity of his use of a fixed stock of appliances.

The results of these studies in demand elasticity are important. Some have argued that residential demand is basically insensitive to price; that is, that elasticity approaches zero. There is no current econometric work to support this conclusion; rather it is based on intuition. An example often cited is that on hot days, customers would not turn off air conditioners, even if prices were somewhat higher; they would simply pay the price. Similarly, customers would light their dwellings almost without regard for the price.

But such examples miss the point of elasticity. The customer's decision on any purchase is made (in the jargon of economics) 'at the margin'. 'At the margin' means, in this context, that the decision is not whether there will be light or dark, hot rooms or cool, but whether there will be a little more or a little less light, or cool air, or electricity consumed. One can turn a thermostat down as well as off. Or again, a modest increase in the price of electricity may justify paying to add insulation, or choosing an appliance that is more electrically efficient.

Sometimes the elasticity of demand for one commodity will be reflected in the substitution of another energy source (say gas) for electricity. In other cases, a price increase will lead to more sparing use rather than substitution. While generalizations are not always useful, the point is that there is no reason to believe electricity is not price sensitive, at least in the long run.

Furthermore, the sensitivity of demand for electricity to price has important implications for pricing-policy. The price sensitivity of demand for electricity, or awareness of it, has played a role in rate-structure design in the past.

[2]Both internal and external resources were employed. The external resources were National Economic Research Associates of New York, and F. Mathewson and Associates of Toronto.

E. FUTURE OF DEMAND-ELASTICITY STUDIES

Progress has been made in estimating the price elasticity of demand, mainly for the residential market. It has been established that the demand for electricity is sensitive to price. Thus pricing-policy will affect the level and pattern of the use of electricity. However, considerable work remains to be done in this area. Several demand models could be considered for further development. Three areas in particular require further refinement.

1. Aggregate demand elasticity studies for the chief consuming sectors: residential, industrial, and commercial.
2. A time-of-use model, to estimate the cross-price elasticities for time of use in each of the chief consuming sectors: residential, industrial, and commercial.
3. An industrial model, to assess the elasticity of substitution (cross-price elasticity) between firm and interruptible power.

IV. PROPOSED PRICING-OBJECTIVE AND PRICING-PRINCIPLES

While still meeting the primary financial objective of recovering costs, pricing can also serve several other objectives, such as fairness, economic efficiency, conservation, environmental protection, and distribution of wealth. For each of these objectives, one or more rate structures can be developed.

The purpose of the costing and pricing-study was to assess the full implications of different pricing-objectives and rate structures. There were many arguments to be assessed, both for and against each pricing-objective identified.

Beyond the varied points and criticisms arising from pricing-policy, two important issues over-shadowed others during the study: availability of capital and the need to reduce demand for primary energy. Even as the economic horizon brightens, these two issues remain as future hurdles for society. The province is in a transitional period, moving from a time of apparent abundance to one of scarcity of resources, and capital and energy are two critical issues.

Given the constraint of scarce and limited resources, the study focused on economic efficiency. In this regard two central questions had to be answered.

1. Could Ontario Hydro's pricing-policy contribute to efficiently allocating resources devoted to producing electricity?
2. Can one find any sound, logically consistent rationale for a pricing-objective of economic efficiency?

For both questions the answer was yes. Ontario Hydro has long recognized that rates can be used to contribute to the efficient allocation of resources devoted to producing electricity. This point is cited in the November 1974 edition of the Corporation's Retail Rate Manual. In Chapter One, entitled "The Importance of Rates', it states:

> *Our rates are important because they can influence the level of use, and thus the demand on resources. They permit a customer to place his own value-judgement on an expenditure for added electrical benefit, compared with other ways he might spend his money.*

The point can be illustrated with a hypothetical example. Consider a residential end rate based on embedded average cost to the utility of 1.5 cents per kilowatt-hour. Assume further that the cost to the utility of an additional kilowatt-hour is two cents.

In this case, the price that the customers face, and respond to, is 1.5 cents per kilowatt-hour. But the cost the utility would incur in meeting increased demands, the cost of input resources such as capital and coal, would be two cents per kilowatt-hour for all further kilowatt-hours.

What this means is that the customer does not see the full cost consequences of using more kilowatt-hours. And as the demand studies indicate, the customer responds to the price he faces.

As the customer buys more electricity in response to the price of 1.5 cents per kilowatt-hour, the producing utility needs more plant, more primary energy, to produce that additional electricity. And the cost of that additional plant and that additional primary energy is greater than the price the customer faces.

So the load growth will be greater than it would have been if the price of electricity had reflected the actual cost of additional production, namely two cents per kilowatt-hour. This leads to using society's resources wastefully and inefficiently.

One way a utility can break out of this circle is to base its rates on the marginal cost of production. If the utility is about to incur costs on behalf of its customers which translate into two cents per kilowatt-hour, then ideally that is the price which the customer should face and to which he should respond. He would then know the cost consequences of his decisions about use.

This example illustrates how pricing can be used to contribute to the efficient allocation of resources devoted to producing electricity. Moreover, it exemplifies in many ways what has happened to Ontario Hydro's cost structure: that is, the marginal costs of production have risen above the embedded average costs.

A. RECOMMENDED PRICING-OBJECTIVE AND PHILOSOPHY

In modern economic theory, the efficient allocation of resources and pricing go hand in hand. For utilities such as Ontario Hydro, marginal cost is the principal theoretical criterion and cost datum for determining the appropriate price. The underlying justification for marginal-cost pricing is briefly outlined here. The complete theoretical foundation, its meaning, and its application to the pricing of electricity, is the subject of Volume V. It is more important to note that, for practical purposes, deviations from the theory of marginal-cost pricing are needed to meet the circumstances of Ontario Hydro and its customers, particularly in dealing with the revenue constraint and in applying the criteria of fairness.

Marginal-cost pricing was found to be consistent with the corporate objective as previously stated, namely

> *To supply the demands of the people of Ontario for electric energy at the lowest feasible cost consistent with safety for its employees and the public and a high quality of service to its customers, and subject to the social, economic, and environmental concerns of the people of Ontario.*

The corporate objective implies that Ontario Hydro should operate on its least-cost curve through time, neither underbuilding plant nor overbuilding. To do this means having the optimal amount of generation and optimal generation mix, based on the customers' requirements. 'Optimal' means that if the prices the customers face reflect the actual costs associated with producing electricity, the costs which Hydro is about to incur on the customers' behalf, then through their decisions about use, their dollar-votes in demanding electricity, the customer will tell the system planners just how much plant to build and how much energy to produce.

Hence if the customer is to receive the right price signal, prices must be based on the relevant costs. These are the marginal costs; the costs which Ontario Hydro is about to commit on behalf of its customers, to meet an increase in their demand.

A price structure that gives as much relevant cost information as is practicable should lead to a lowest-feasible-cost system through time. The customer should receive the relevant information about the cost of energy (kWh) and the rate of use of kWh (kW) during the various time periods. Aware of the cost implications of his decisions about using electricity, he would then spend his dollars in a way that minimizes his costs or maximizes his satisfaction. The system planner would then get back the necessary information as to optimal load growth and optimal time of use.

The feedback loop would be complete. The customer would receive the relevant cost information through the rate structure. He would then have the opportunity to make his own cost-minimizing calculation about use and willingness to pay. This information, in terms of use, rate of use, and time of use, would feed back to the system planner. The feedback loop would give the system planner the relevant information about load growth and optimal generation mix. It would be the relevant information because the customers' decisions would be based on prices which reflected the relevant marginal costs of production.

Hence the recommended pricing-objective is consistent with the corporate objective, which is that the pricing-structure should contribute to the efficient allocation of resources devoted to producing electricity.

The purpose of marginal-cost pricing, then, is to make the cost the customer saves or incurs from his decision about use reflect the cost incurred or saved by Ontario Hydro.

Marginal cost represents the cost a customer imposes on the Corporation and society to provide him with the electricity he uses. As M. Boiteux of Electricite de France has noted,

> *The object of selling at marginal cost is to provide a valid guide to help users in their choice, in such a way that the least-cost solution for them is also the least-cost solution for society.*

B. COST VARIATION AND CUSTOMERS' DECISIONS

A pricing-system should be designed to reflect the system's costs. There is no single characteristic of the output (kWh) of an electric utility against which all costs vary. Four characteristics significantly affect the costs of Ontario Hydro and the utilities, and the customers' demand for the product. For each one, there is a consumption decision facing the customer. The four consumption decisions are:

1. Decision to Become a Customer

There are identifiable costs associated with the customer. These may be called customer costs, and lead to a customer charge.

2. Decision about Use (kWh)

There are identifiable costs that vary according to the energy requirements of the utility (cost per kWh), resulting from customer demands affecting use. These are called energy costs, and lead to an energy charge.

3. Decision about Rate of Use (kW)

There are identifiable costs associated with the capacity requirements of the system (cost per kW), which result from customer demands affecting the rate of use. These are called demand costs, and lead to a demand charge.

4. Decision about Time of Use

There are identifiable costs which vary according to the time period and affect the energy requirements of the system. Generally, this means that there is a cost per peak kilowatt-hour which is different from the cost per off-peak kilowatt-hour. This cost differential leads to a rate differential between peak energy use and off-peak energy use. It also provides a basis for assigning a demand charge.

A clearer explanation of use and rate-of-use costs might be made if one considered the analogy with water. Assume that storage tanks are employed to meet extra water requirements during peak periods. Use refers to the actual gallons of water used. Use costs for gallons of water would be analogous to energy or kilowatt-hour costs. Rate of Use refers to the rate at which water is used: that is, gallons of water per hour. Rate-of-use costs for gallons of water per hour would then be analogous to demand or kilowatt costs. These are based on the maximum demand placed on the water supplier in supplying his customers. These costs consist of the annualized costs of (a) the storage system required to meet this maximum demand and (b) the delivery system, which is made up of water pipes sized to meet the maximum demand for water during the peak period.

What does all this mean for pricing? Consider first the demand-energy split, an issue which has been the subject of debate for some time.

C. THE DEMAND-ENERGY SPLIT

The basis for the demand-energy split is vital, because of the implications of the split for capital spending and the consumption of primary energy. At issue is the appropriate basis for splitting total bulk-power costs between demand and energy. The division is necessary given the nature of the commodity. Kilowatt-hours, as such, cannot be stored; and therefore the supplier must install additional plant to serve the maximum or peak rate of use over a given stretch of time. This entails a two-part charge: an energy charge expressed in cents or mills per kilowatt-hour to reflect the customer's use of the commodity, electrical energy; and a demand charge expressed in dollars per kilowatt to reflect the rate at which he uses kilowatt-hours.

The price relationship between demand and energy, as the split determines it, can have a significant effect on the mix of input resources required, whether for capital or for primary energy. The absolute price level for both demand and energy which the split gives can affect the magnitude of the basic resources (capital and primary energy); and the method of assigning demand costs to the customer can affect the amount of basic resources required. The potential shortfall of capacity varies according to the intensity of demand, and reaches a peak during the interval of maximum demand (whether in a day or in a year). Because of this potential shortfall, the planner has to augment the system in these periods of maximum demand, while at other times he has excess capacity on his hands.

> ***To achieve the proper mix of input resources, capital and energy, the demand-energy split should be based on marginal costs.***

As Exhibit IV-1 shows, the demand-energy split, based on marginal costs for 1978, would be 35-65. A demand-energy split based on the marginal costs of production will lead to the proper rate of substitution between rate of use and use. The customer can make his own trade-off between demand and energy, based on the relevant cost information. Prices will show the relative cost consequences of consuming one more *kilowatt* or one less, and the cost consequences of consuming one more *kilowatt-hour* or one less.

It should be recognized that a demand-energy split based on marginal costs will lead to a shift in costs between customer classes and between customers within a class. Customers with high load factors would face higher costs than under the existing demand-energy split.

Exhibit IV-1

Projected Demand-Energy Split. Based on Marginal Costs, Time Averaged and Pro-rated to the Revenue Requirements 1977-1979

	Marginal Demand Cost $'000	Pro-rated Demand Unit Rate $/kW	%	Marginal Energy Cost $'000	Pro-rated Energy Unit Rate ¢/kWh	%
1977	811,918	40	35	1,538,083	1.169	65
1978	960,887	47	35	1,772,507	1.335	65
1979	1,132,488	53	37	1,951,044	1.444	63

D. TIME-OF-USE PRICING

Demand varies periodically over the day and over the year. These variations in the rate of use lead to time-based cost differentials. That is, the resources the Corporation requires to serve load during the period of peak or maximum demand of the system are greater than the resource costs of serving load in the off-peak period. A kilowatt-hour consumed between noon and one o'clock p.m. has a higher cost than a kilowatt-hour consumed between midnight and one o'clock a.m. If the objective of efficiency is to be met, it is important for prices to reflect these time-based cost differentials.

As was mentioned in the discussion of the demand-energy split, the method of assigning demand costs to the customer affects the amount of basic resources required. Because the demand for electricity is periodic, varying by time of day and season of the year, and because its supply basically cannot be stored, the costs of supplying additional consumption also vary. In order for prices to track costs properly, it is recommended that

> *Seasonal time-of-day rates should be introduced now for users with monthly peak loads of 5000 kilowatts or more.*

It is further recommended that load data should be gathered and analysed for customers with monthly peak loads of between 3000 and 5000 kilowatts, with a view to introducing seasonal time-of-day rates for these customers as well.

This method of pricing requires sophisticated metering, such as digital demand recorders. The 3000-kilowatt level was chosen because most customers with loads over 3000 kilowatts already have such metering installed. However, load data for those customers with loads between 3000 and 5000 kilowatts was not available for analysis, from which to forecast the effects of time-of-day rates.

At present cost-benefit analysis (Volume VIII, Appendix VI) does not appear to justify introducing time-of-day rates for residential customers. However, it is recommended that

> *A five-year experiment should be conducted with time-of-use rates for customers with average monthly power demands of 3000 kilowatts and less, including residential customers.*

With time-of-day rates, each customer would see the cost consequences of his consumption patterns. Time-of-day rates for all large users with average monthly uses of over 3000 kilowatts, and possibly future on an optional basis for users under 3000 kilowatts, would offer maximum benefits with minimum costs. Time-of-day rates could lead to more efficient use of resources devoted to producing electricity. Furthermore, there will be no intentional cross-subsidization of peak use by off-peak use.

What this means to the industrial user, for example, is that there should be a dollar incentive to shift his load into the off-peak period. For example, a three-shift operation might run more electrically intensive equipment during the midnight shift, and reduce its load in the other two shifts. A single-shift company might deem it now had incentive enough for incurring other costs associated with a double shift to take advantage of the off-peak rates, or consider cutting its load on peak by introducing more efficient equipment over the long run. The important point is that the customer will face the cost consequences of his decision about use. The price he pays or saves would reflect the cost of producing one more or one less kilowatt-hour in the peak or the off-peak period.

E. IDENTIFYING THE PEAK-PERIOD AND ASSIGNMENT-OF-CAPACITY COSTS

The question of identifying the peak period, and effectively tying prices based on marginal costs to peak demand, is one more difficult part of time-of-use pricing. Although *after the fact* it is possible to identify a particular hour of the year when the peak demand actually occurred, it is generally unknown *before the fact* exactly when it will occur or exactly how high it will be. System planners do have expectations about how high the peak load will be, as well as which are the potential peak hours. They use these expectations in designing the system and providing

for reserve capacity and maintenance scheduling. Because rate periods and associated prices are established before the fact, knowing the potential peak hours and the expected costs is essential for establishing rate periods and estimating marginal costs.

More technically, demand is uncertain for a particular stretch of time in the future at any set of prices. Normally, a good deal is known about the probability distribution that characterizes the uncertain demand. For Ontario Hydro, there is not much variability in load from one hour to the next during the daytime hours in a particular season. The system faces a broad daily peak from about 0700 hours to 2300 hours, where the load at one hour is little different from that in several other hours. Furthermore, the average daily peak load for the potential peak days as a group may be very close to the actual peak. Such load characteristics are generally the easiest situations for which to define pricing-periods and to tie closely together prices charged and marginal costs incurred.

Finally, as Ontario Hydro moved from the current pricing-system to a system of peak-vs-off-peak pricing (for large users), consumption patterns would change. Some have concluded that one effect of peak-load pricing would be to shift the peak to other times, and that system planners and rate-makers would face the task of chasing peaks. However, such a situation would only arise if all capacity costs were assigned to a very few identifiable peak hours. If, for example, 2:00 p.m. on Monday, December 21 were chosen as the hour to which to assign all the annual marginal capacity cost, it would be reasonable to presume that much load would shift from 2:00 p.m. to 1:00 p.m. or 3:00 p.m. Accordingly, the peak period must be defined so as to eliminate such transitory movements, and avoid misapplying the principles of marginal-cost pricing.

How one assigns capacity costs to the costing-periods depends on the relationship between demand and available capacity in those periods. Specifically, the relative loss-of-load probabilities for each costing-period are used to assign capacity costs to those periods. The loss-of-load probability measures refer to the estimate of the probability that available capacity will fall short during a particular set of hours. Following the recommendation in Section V,

> ***The winter peak period would be defined as the months of October to March inclusive, and the summer peak period as April to September inclusive.***

These periods were chosen on the basis of an analysis of relative loss-of-load probabilities, carried out in the course of determining the costing-periods for the marginal-cost study (Volume VII).

> ***The daily peak period would be defined as 0700 hours to 2300 hours Monday through Friday (excluding statutory holidays), and the marginal capacity costs would be assigned to the customer on the basis of his average monthly non-coincident peak demand in the peak period.***

It should be noted that approximately 53 per cent of the total hours in the year are off-peak hours.

Capacity costs would then be reflected in the price charged during a fairly large number of hours, and problems of shifting peak would be minimized. On the other hand, prices would track costs through time, and the system load factor might improve if customers reduced their peak consumption by shifting load to the off-peak period. This might be limited, however, because of the length of the peak period.

F. THE METHOD OF TREATING SURPLUS REVENUES

The implications of the foregoing recommendations for rate-structure design are outlined in the next section. However, if all characteristics of the utility's output are to be priced at marginal costs (customer, demand, peak energy, and off-peak energy), then the revenues generated will exceed the revenue requirement. This is because the revenue requirement is based on historical accounting-costs, and at the present time marginal costs are above those average embedded costs.

To avoid such surpluses, one must adjust the prices based on marginal costs so that the revenues generated just meet the revenue requirement. Furthermore, the method of adjustment must be consistent with the pricing-objective of contributing to an efficient allocation of resources devoted to producing electricity.

It is necessary, then, to depart from marginal-cost pricing where the price signal has least influence on the customer's decision about use. Of the consumption decisions outlined, the decision to become a customer is the least sensitive to price. The other decision components (use, rate of use, and time of use) would usually be much more sensitive to price. It is more important, then, to maintain the integrity of the price signals for use, rate of use, and time of use. On the other hand, the signal relayed through the customer charge may be distorted over a reasonable price range. Hence the demand charge and energy charges should reflect their marginal costs. The customer charge may be adjusted downwards to eliminate the surplus, with minimal distortion to the intended price signal and hence to the customers' decisions.

The methodology of returning the surplus is discussed in the next section of this volume. The guiding principle used in developing a method of surplus return was to be fair while maintaining the pricing-objective of efficiency.

G. EFFICIENCY AND FAIRNESS

Considerations of fairness have always played an important role in setting rates. In its simplest form, fairness has great appeal to rate-makers and the public alike. Obviously, the community desires all instruments of public finance (taxes, government spending, prices set by public utilities, etc.) to be fair.

On some criteria of fairness the community will be found united, once the question in hand is well understood. These criteria raise no question of conflict of interest; they may be termed the agreed criteria of fairness. The traditional and proposed view of fairness in ratemaking deals with agreed criteria. An example would be the reduction of uncertainty in the utility's prices.

Other criteria of fairness produce sharp differences of opinion, since they call for making some persons worse off in order to benefit others. They are conflict-of-interest criteria. A conflict criterion, therefore, supplies a standard, a guide to policy, but one imposed against the wishes or judgement of some members of the community. An example of this would be to use utility prices to redistribute wealth (for example, through lifeline rates). The traditional and proposed view of fairness in ratemaking does not concern itself with conflict criteria. Utilities have traditionally viewed conflict criteria as lying in the domain of government. Ontario Hydro has not viewed its rate structure as a policy instrument to deal with social objectives involving conflict criteria.

It has been recommended that the price structure should be designed to contribute to the efficient allocation of resources. It is further recommended that

In meeting this efficiency objective, the price structure should be as fair as is practicable.

Fairness means equal treatment of equals, based on criteria which reflect general agreement in the community. These agreed criteria of fairness may be listed as follows:

1. The price-structure should return the benefits of historical investment to the utility's customers in a way that maintains distributive impartiality. That is, the benefits of historical investment should not be used to subsidize one particular group of customers at the expense of any other.
2. The price-structure should maintain the integrity of the cost-pooling concept.
3. There should be no seniority rights in the pricing-structure. All consumption is always new, for the customer can decide to discontinue it at any time.
4. The price-structure should be impersonal: that is, there should be no undue discrimination. Any rate structure will be discriminatory to some degree. The real question is whether the discrimination among customers can be justified.
5. The price-structure and changes in the price level should be defined clearly, so that the customer is aware of the price he will pay if he undertakes a specific course of action. This is the criterion of certainty in prices.
6. A change in corporate policy (for example, on system reliability) should not lead to unduly abrupt changes in prices or service received. This is the criterion of continuity in prices.

For a further discussion of the efficiency objective and fairness, see Volume V.

H. EFFICIENCY AND CONSERVATION

Some critics claim that the promotional or declining-block structure of energy rates contributes to waste of electricity. At the same time, it is alleged that the price structure does not encourage conservation. Indeed, many people are concerned with the seemingly unending growth spiral of energy consumption.

But what exactly does energy conservation mean? In what sense is primary energy being wasted? These questions must be answered in order to develop a meaningful framework for a conservation policy.[3]

With a depletable resource, such as oil or natural gas, *conservation* means using less in the present and so having more to use at some future time, if desired. Reduced use today is considered justified if the costs expected from postponing consumption now are less than the present value of the future benefit stream which having more to use later would create. The discounted future benefits may be defined as the social-opportunity cost of present consumption.

With electricity, society is not dealing directly with a depletable resource. It is not within the mandate of an electric utility to deal with the optimal pricing of depletable resources to effect conservation. However, the electric utility does have a duty to ensure that its pricing-policy does not encourage wasting its product.

Waste does not mean throwing electricity away, but rather refers to additional consumption that would not occur if the price facing the customer equalled the cost of producing that additional consumption.

This approach to conservation and waste holds considerable promise. Consider some examples.

There are several cases in the present rate structure where the marginal price to the end user is zero. It is recommended that

The marginal price to the end user should never be zero.

The cost the customer incurs or saves from a decision about use should reflect the cost incurred or saved by the utility.

Consider the minimum bill for cottage customers, which for 1976 lets the customer use as much as 240 kilowatt-hours,[4] or flat rates for water heaters. These are two cases where the marginal price to the customer does not reflect the real cost of production, and hence leads to wasteful use of electricity that might not otherwise have occurred.

Consider also bulk-metered apartments. Here the marginal price to the customer is zero. Electricity is included in the rent. The customer, therefore, does not see the cost consequences of consuming a little less electricity or a little more.

Several independent studies have shown that residents in bulk-metered apartments tend to use more electricity than those with individual meters. Findings from an American study by Mid-West Research Institute showed that the ratio of consumption by bulk-metered residents to that of individually metered residents ranged from 108 per cent to 269 per cent, averaging 134 per cent. Within Ontario Hydro, a more modest study of the same type showed that bulk-metered apartments as a group consumed 39 per cent more electricity than comparable apartments individually metered. On average, the excess consumption amounted to 1,443 kilowatt-hours a suite for 1974.

On the basis of the foregoing findings, reversing the movement to bulk metering has been suggested as a conservation measure. A resource cost-benefit analysis of the feasibility of abandoning bulk metering in apartment suites has shown that such a move would yield resource savings, amounting to over 26 billion kilowatt-hours by the turn of the century.

To bring back individual metering would mean an increase of approximately $136 million in operating and maintenance costs for the next 25 years. However, cautious estimates of benefits fall in the area of $166 million for the same period, so that such a move could realize an aggregate net resource benefit of at least $30 million. However any policy decision on bulk metering would require consideration of conflicting objectives.

Efficiency, marginal-cost pricing, and conservation are compatible. If the price of electricity were based upon marginal costs, then the customer would face the cost consequences of using one more kilowatt-hour or one less. The decision would lie with the customer. Once he knew the price of electricity, he could trade off the benefits of consuming a little more or a little less against the costs.

The customer is the best judge of his own tastes, and of the further satisfaction he would gain or lose from using a little more or a little less of any particular good or service. No one person or

[3] The issue of conservation and pricing is reviewed in detail in Volume VI, Part III
[4] This is an illustrative example, and in practice the minimum bill is being phased out in the rural retail system. Minimum bills should be discontinued for all classes of customers in all retailing utilities.

group has the wisdom to dictate the tastes and preferences of all individuals in society.

I. DETERMINING MARGINAL COSTS

The methodology for determining Ontario Hydro's marginal costs of production is described in Volume VII, *Costing Methodology for Determining Marginal Costs.* 'Marginal cost' may be defined as the cost of producing a permanent and quantitatively small change in output, when all resource-cost inputs are optimally adjusted to change. Generally marginal cost refers to the increment in cost arising from a permanent increment in output.

The marginal-cost study was undertaken by National Economic Research Associates (NERA) of New York. The costing methodology represents the 'best' estimate of marginal costs, given the state of the art. However, the methodology for determining marginal costs should be analysed on a continuing basis. Such analysis will allow for improving the methodology as improvements take place in the state of the art.

Generally, the measurement of marginal costs may be described as follows:

1. *Forward-looking.* Marginal costs are based on the system-expansion plan of the planning-period and cost estimates of the system planner applicable to the facilities to be installed.
2. *Current dollars.* Inflation is disregarded in computing marginal costs. For example, the marginal-cost study was developed in 1975 dollars. Changes in relative price are taken into account, however, insofar as they affect the system planner's least-cost generation mix.
3. *Time-related.* The methodology accounts for the cost differences in producing energy in different periods of the day and the year.

The costs to be estimated for purposes of marginal-cost pricing are meeting an increment of demand, providing an increment of energy, and connecting a customer. These marginal costs will reflect the capital, operating and maintenance costs of the whole gamut of facilities, from generator to meter, needed to supply these increments. They also include associated overheads, essentially the marginal ones. All costs computed are based on the prices currently prevailing. The cost estimates developed will have to be adjusted annually.

The cost data employed are the same data as the system planner uses. The costs are those which the Corporation is about to incur on behalf of its customers in providing a least-cost system.

J. LEADING CRITICISMS OF MARGINAL-COST PRICING

While marginal-cost pricing appears an attractive alternative, it has aroused some controversy and criticism. Some of the criticisms have already been covered implicity, but it is useful to identify the chief arguments that have been made against marginal-cost pricing. The four main criticisms are as follows:

The "Second-Best" and "All-or-Nothing" Argument

The argument used most often against marginal-cost pricing is the 'second-best' position. It has been emphasized that the rule of marginal-cost pricing is essentially an all-or-nothing rule, in the sense that there is no advantage in applying it to one industry or service if it is not applied at the same time to all others. Indeed, applying it to one industry alone might well work havoc rather than good, as far as allocating resources is concerned.

The Argument about Distribution of Wealth

It has often been pointed out that one need accept marginal-cost pricing as efficient only if one is willing to place a similar value on the distribution of wealth. Two positions have to be considered: the current distribution of wealth, which decides how many dollar votes each buyer has in deciding what to order the economy to produce, and the distribution that results from equating price to marginal cost. It should be noted that this is an ethical argument, not an economic one.

The Argument of Calculation of Marginal Cost

Another important objection to marginal cost as a basis for pricing is that it has no single definition, but rather a considerable variety of definitions, each contingent on the special circumstances of a particular case. Furthermore, any measure of marginal cost is based on estimates, accounting-costs included. It is said; accordingly, to be an unsuitable basis for a general rule and impractical to carry out.

The Argument of Surplus Revenue

Because the revenue requirement is based on historical accounting-costs, prices based on marginal costs would lead to surplus revenues. Therefore, if the revenue requirement is to be met, the principles of marginal-cost pricing must be compromised. It is not clear just how great a loss of economic efficiency would result from such adjustments to the appropriate marginal cost. It might not even be clear whether the unavoidable loss of efficiency was minimized in making this adjustment.

There are other criticisms, ranging from the failure to recognize social costs to the lack of knowledge about demand elasticities. Volume Five, *The Theoretical Foundations of Marginal-Cost Pricing,* deals with these various criticisms in more detail. It also demonstrates the invalidity of these criticisms.

The recommendations on the proposed pricing-objective and pricing-principles can be summarized as follows:

1. ***The price-structure should contribute to the efficient allocation of resources devoted to producing electricity.***
2. ***The demand-energy split should be based on marginal costs.***
3. ***Seasonal time-of-day rates should be introduced now for users with monthly peak loads of 5000 kW or more.***
4. ***Load data should be gathered and analysed for customers with monthly peak loads between 3000 and 5000 kW, with a view to introducing seasonal time-of-day rates for those customers.***
5. ***A five-year experiment should be conducted on using time-of-day rates for customers with monthly peak power demands of 3000 kW and less, including residential customers.***
6. ***The winter peak period should be defined as the months of October to March inclusive, and the summer peak period as April to September inclusive.***
7. ***The daily peak period should be defined as 0700 hours to 2300 hours Monday to Friday (excluding statutory holidays), and the marginal capacity costs should be assigned to the customer on the basis of his average monthly non-coincident peak demand in the peak period.***

8. *The price structure should be fair as is practicable.*
9. *The methodology for determining marginal costs should be analysed on a continuing basis.*

V. THE ALTERNATIVE PRICING-OBJECTIVES

Four other pricing-objectives were considered in some detail. Not all these are inconsistent with the proposed pricing-objective of efficiency. Volume VI considers the alternative pricing-objectives, and the arguments for and against treating them as primary. The four alternative pricing-objectives were

A. Fairness,

B. Conservation,

C. Distribution of Wealth, and

D. Environmental Protection.

A. THE FAIRNESS OBJECTIVE

One school of thought would set 'fairness' as the primary pricing objective, and link it explicitly with a fully distributed pricing-system (FDC) employing average costs. With a fully distributed system, the fixed, overhead, and joint-cost portions of the revenue requirement are allocated 'fairly' among the various customer classes, based on the relative consumption characteristics of the classes and so on their adjudged responsibility for incurring these costs. The resulting revenue requirement of each class is then similarly distributed among the customers.

However, others claim that fairness demands that the cost of customers decision be the price that he pays for that decision.

However, fairness is not the sole object of fully distributed average-cost pricing, and consequently should not be tied solely to FDC. As was said earlier in this volume, any pricing-system a public utility uses must ultimately be fair. Besides fairness, objectives such as simplicity, accountability, and flexibility are incorporated into fully distributed cost pricing.

On the other hand, economic efficiency has not been an explicit objective of FDC. The inclusion of this objective, or indeed the fitting of any retail rate schedule to the principle of marginal-cost pricing, is greatly hampered by the nature of the wholesale rate that the retailing utility faces. The design of the retail rate must be compatible with the movements in the overall revenue requirement, which is strongly influenced by the wholesale cost. In Ontario, where there is an environment of retailing and wholesaling utilities, a wholesale rate based on cost averaging has led directly to retail rates based on averages to follow suit.

At the wholesale level, there are three fundamental types of averaging implicitly being made with Ontario Hydro's current rate form.

1. Historical Averaging

Historical accounting-costs, using dollars of different vintage, are used to develop rates. For example, the costs associated with older plant through in the depreciation accounts are averaged in with current costs of new plant.

2. Demand and Energy-Cost Averaging

The demand and energy costs to some extent reflect the average costs of supply. In other words, the demand and energy rates incorporate adjustments to match revenue with the historical accounting-costs of the mix of generating-plant technology and of the fuel mix (hydraulic, nuclear, and fossil).

3. Cost Averaging Through Time

The higher costs of providing electricity in the peak period (by season and by day) are averaged in with the lower costs of providing electricity in the off-peak periods.

A fully distributed average-cost pricing-system is less expensive, and more attractive administratively, than other techniques of costing and pricing. As costs are averaged over time and output, a minimal amount of administrative cost (metering and load data) is required. In turn, the rate structures are relatively straightforward.

More importantly, it is suggested that there is a high degree of accountability in the rate structure, since average-cost pricing is based directly on the projected actual book costs over the time frame in which the rates are to apply. Because the revenue requirement will be exactly met, all other things being equal, there will be no surplus revenues. This accountability provides a standard for evaluating past allocations of cost to the various customer classes, and therefore a reference point for future decisions in this regard.

A fully distributed average-cost pricing-system has the flexibility to close with the revenue requirements yet still remain fair. Within the limits of practicality, there is no undue discrimination between classes. Where the quantity and rate of use are the same, the total charge to the customers is the same, unless a difference is justified by identifiable cost differences in the conditions of service. Ideally, at the same time each customer shares proportionately in the historical benefits of investment.

Every pricing-system generating only enough revenue to meet a revenue requirement based on historical costs does in fact provide the historical benefits of investment to all customers. However, fully distributed average-cost pricing returns the benefits to each individual customer, as much as possible, on the basis of that customer's use. This process may be deemed more distributionally impartial than other pricing-philosophies with markedly different return processes.

There are several criticisms of fully distributed average-cost pricing. First, the distribution of costs between demand and energy related is judgemental and therefore open to challenge; some judgement, though, is required in all pricing-policies.

The most fundamental criticism of FDC so far is that it has not treated the marginal cost of producing electricity explicitly as a pricing-instrument, and thus sidesteps the question of economic efficiency. Insofar as the use of electricity is sensitive to price, underpricing marginal use at average costs will encourage unnecessary growth in capacity and fuel requirements.

B. CONSERVATION OBJECTIVE AND THE INVERTED RATE STRUCTURE

Some conservationists claim that pricing should be used to restrict growth, perhaps to achieve zero energy growth. The rate structure through which this conservation objective would be achieved is the inverted one. This means that prices would be raised to obtain some arbitrarily selected growth rate, and would no longer track costs. There would of course still be a revenue constraint, as with any other method of pricing.

For example, assume an inverted rate structure with three blocks: 0 to 250 kilowatt-hours; 251 to 500 kilowatt-hours; and 501 kilowatt-hours and over. The price per kilowatt-hour would be progressively higher in each block. There is a twofold justification for the inverted rate structure. First, because demand for electricity is sensitive to price, higher prices will reduce the demand. Second, the burden of an inverted rate structure would fall primarily on 'unnecessary and luxurious' power consumption, after allowing each user a reasonable amount of electricity at a lower price to meet basic needs.

The primary drawbacks to the inverted rate structure are these. First, it is not based on costs. Hence there is no logical foundation for establishing the number of blocks, the length of each block, or the price level in each block. Second, low use does not necessarily correspond with 'necessary' power consumption, nor does high use necessarily correspond with 'unnecessary and luxurious' consumption.

C. OBJECTIVE OF REDISTRIBUTING WEALTH: LIFELINE RATES, ENERGY STAMPS, ETC.

Another objective pricing-policy may serve is redistribution of wealth. The objective is clear enough: subsidizing users of electricity with low incomes. Three redistributive programs have been proposed in recent years: lifeline rates, energy stamps, and an energy tax credit.

1. Lifeline Rates

A lifeline rate may be defined as a low uniform charge for the first several hundred kilowatt-hours each residential customer uses.

This practice is simply one of redistributing wealth by having other users of electricity cross-subsidize low-use residential customers. There are various ways to recover the revenue forgone under such a scheme, and the burden imposed on others will vary according to the recovery method used. However, all methods involve recovering lost revenue through increasing rates for consumption beyond the lifeline level. A likely approach would involve an inverted residential rate structure along with some increase for industrial and commercial rates. An implicit (and false) assumption here is that income and use of electricity are closely related.

2. Energy Stamps or Vouchers

Energy stamps are an example of a method of redistribution which may be financed and administered by the government. In this the energy-stamp proposal closely parallels the American food-stamp program. The stamps would be used to pay either utility or fuel-oil bills.

3. Energy Tax Credit

An energy or electricity tax credit would be similar in form and working to the Ontario property-tax credit. Individuals and families would receive tax rebates based upon energy use and income. They would have to keep their bills for electricity and other forms of energy as proof of actual use.

Of the three redistributive programs outlined, an energy tax credit appears to be the least unattractive, for the following reasons:

1. It would minimize distortions in consumption preferences between energy types in the economy.
2. The poor would be more easily and more accurately identified.
3. The use of tax credits would tend towards negative income taxation, which some see as the most efficient way to meet the objective of redistributing wealth.

The strengths and weaknesses of each of these distribution programs are considered in more detail in Section IV of Volume VI. There are major drawbacks to any programs for redistributing wealth that Ontario Hydro might undertake. In summary, they are:

1. Inefficient allocation of the resources used to produce goods and services within society.
2. Inefficient allocation of the resources devoted to producing electricity.
3. Inefficiency in identifying and helping low-income individuals and families in the least costly way.

The objective of income distribution should be therefore rejected as an alternative for pricing-policy. Social engineering through rates would cause some customers to cross-subsidize others, and is not within the Corporation's mandate. Furthermore, the Government ought not to use the Corporation as a policy instrument for redistributing wealth. Such redistribution policies would effectively destroy cost causality and an efficient pricing-system.

D. OBJECTIVE OF ENVIRONMENTAL PROTECTION AND SHADOW PRICING

One can make a strong case for environmental protection as a pricing-objective. To attain this, it has been suggested that a shadow price equal to the marginal net damage caused in producing electricity should be added to the marginal private cost of the utility, in order to arrive at the appropriate price for electricity. The National Energy Board has implicitly endorsed this pricing-practice for electricity exported to the United States.

The argument is straightforward: the total social cost of production equals private cost plus external cost.

1. *Total social cost* refers to the total economic cost incurred by the production and market activity of a particular body.
2. *Private cost* refers to those costs faced by, and internal to the economic decision unit.
3. *External cost* refers to the money value of the externalities caused by the production and market activity of particular economic-decision units on other persons or decision units that are external to the producing unit's decision-making process and market activity.

The principle underlying shadow pricing is clear. Given that the demand for electricity is sensitive to price (exponents of shadow pricing claim), prices reflecting private costs only are too low, and lead to an output that is too high. That is, society is devoting too great a share of its resources to producing electricity. A fully efficient pricing-scheme would reflect marginal social costs. Efficient prices would be higher, then, and output lower, if price equalled marginal social cost.

Such a pricing-policy would be consistent with economic theory. The requirements of economic efficiency dictate a 'shadow price' upon the productive activities of the generator of an externality. Such a shadow price should equal the marginal net damage from producing electricity. Hence price would equal marginal social cost. The customer would then face a price which represented the real resource cost consequences of using one more kilowatt-hour, or one less.

However, there are two important drawbacks to shadow pricing at present.[5]

1. Information Requirements

As was noted, the proper shadow price equals the marginal net damage from producing electricity. At present, it is virtually im-

[5]There are seven practical drawbacks to shadow pricing enumerated in Part IV of Volume V. The two dealt with here are the most significant.

possible to obtain a reasonable estimate of the money value of this marginal damage, since it consists largely in such things as damage to persons' health and to the beauty of the countryside. Moreover, the number of parties involved, and the complex interdependencies among them, make the task even harder.

2. Inflexibility

One drawback to a shadow pricing scheme is implicit throughout all discussions: its lack of flexibility. Shadow prices would be hard to change on short notice. They would be hard to carry out on a regional basis. They could not allow for differences in the effects of equal amounts of emission upon the effective level of pollution. Such inflexibility makes shadow pricing a questionable tool for dealing with the external costs of producing electricity.

In the light of the foregoing analysis, shadow pricing or an externality tax, should be rejected as an alternative for pricing-policy. It is recommended that the Corporation should base its price on marginal private costs, while meeting the environmental standards and criteria set by the Government. In meeting prescribed standards, of course, external costs are internalized. From then on, the Corporation would consider all costs in setting prices based on marginal costs.

E. SUMMARY OF RECOMMENDATIONS

A summary of the recommendations follows.

1. *The objective of redistributing wealth should be rejected as an alternative pricing-policy.*
2. *Shadow pricing, or an externality tax, should be rejected as an alternative for pricing-policy.*
3. *Ontario Hydro should base its price on marginal private costs, while meeting the environmental standards and criteria set by the Government.*

VI. PROPOSED PRICE STRUCTURE AND PRICE SCHEDULES

To meet the objective of efficiency, it is important for the price schedules to provide as much relevant cost information to the end user of electricity as is practicable.

The guiding principle, then, in designing a rate structure is to ensure that the marginal use of electricity is priced at the marginal costs of generation and distribution systems, subject to the previously defined constraints of fairness and the revenue requirement. Rate structures were designed to ensure the integrity of the cost information flowing from the bulk-power system through the retailing utilities to the end customer, while picking up the costs of distribution or delivery on the way. The proposed rate structure is called the 'flow-through' approach, because it 'flows' the marginal-cost information from the producer (Ontario Hydro) through the distributors (the municipalities) to the end user of electricity. At the same time, the rate-structure proposals do not interfere with the local autonomy of the municipalities.

There are three chief areas for which recommendations are made:

1. Customer classes at the bulk and retail level;
2. Proposed price structure and schedules at the bulk level; and
3. Proposed price structure and schedules at the retail level.

The detailed outline of the pricing-proposals and illustrative rate schedules are shown in Volume VIII: Detailed Proposals for Rate-Structure Design.

A. CUSTOMER CLASSES

1. Customer Class at the Bulk Level

The present costing-classification of Ontario Hydro at the wholesale level is composed of 353 municipal utilities and the Power District, which is a retailing-agency of Ontario Hydro. The total costs, associated with the common generation (production), grid, and radial transmission (common delivery) costs, with other associated joint and fixed costs, are allocated to each of the 354 customers in a uniform two-part rate. This rate consists of a single energy charge in mills per kilowatt-hour and a single demand charge in dollars per kilowatt of demand. This demand charge, which is a rate-of-use charge, has generally accounted for more than half the total bill of each distributing utility. Each monthly total of the billed kilowatts of demand exceeds the total kilowatts of load for the system, due to the non-coincident feature of the billed kilowatts.

The total dollars associated with kilowatts for the Power District are assigned to two classes: Direct Industrial and the Rural Retail System (of Ontario Hydro), based on the non-coincident monthly demand of each. Since this again exceeds the total billed demand of the Power District, the dollars per kilowatt of demand for the class of direct industrial customers amount to less than the dollars per kilowatt for the Power District.

Under this classification system, a direct industrial customer with a load factor of 100 per cent imposes a higher charge on the Power District than a customer with a lower load factor, because of its coincidence with the peak of the Power District. Demand and energy charges to these industrial customers have therefore been adjusted in their rates to reflect this costing-characteristic, and to diminish the benefit of diversity as the load factor increases. This has led to a lower demand and higher energy charge for the direct industrial customers than for the retailing utilities. The current procedure generally has led to a higher total bill to the utility for a load of similar shape and magnitude than for the direct industrial customer, given identical delivery conditions.

At the same time, large industrial customers of the retailing utilities have faced different monthly bills from direct industrial customers and customers of other utilities for identical loads, load shapes, and delivery conditions. This has led to considerable debate about the present customer classification among the concerned parties: the direct industrial customers, the retailing municipal utilities, and large customers of these utilities. Each of these groups faces different demand and energy charges, and thus different total bills, for identical load, load characteristics, and delivery conditions.

To minimize these differences, it is recommended that the unit rate for energy and rate of use of energy (kW) should be the same for similar delivery conditions, and so eliminate the apparent discrimination. For costing-purposes, then, there would be a single class of customers, comprising all retailing utilities (including Ontario Hydro's retail system) along with all large industrial, commercial, or institutional users of electricity. (See Exhibit VI-1) Of course, this recommendation would shift costs between present customer classes and within customer classes.

For the time being, large users would be defined as retail customers with monthly peak loads of 5000 kilowatts or more. The intent is to reduce this level to 3000 kilowatts as soon as load data can be gathered and analysed for customers with monthly peak loads of between 3000 and 5000 kilowatts. The level of 3000 kilowatts was chosen because customers with greater loads than that are a fairly uniform group. Most own their transformation and their protective switchgear, are not served off the distributing-system, and already have digital demand recorders installed. But since this level was chosen without data, it could turn out that the proper one ought to be higher or lower. Meanwhile, the level of 5000 kilowatts should be retained for defining large users.

The new classification would consist of the sum of the net loads of all retailing utilities (including Hydro's retail system) plus the loads of all large users who are customers of the various retailing utilities. The retailing utilities' net costing-load would not include any customer loads over 5000 kilowatts. Hence the total number of costing-loads would be 354 retailing utilities plus approximately 201 large-use customers.

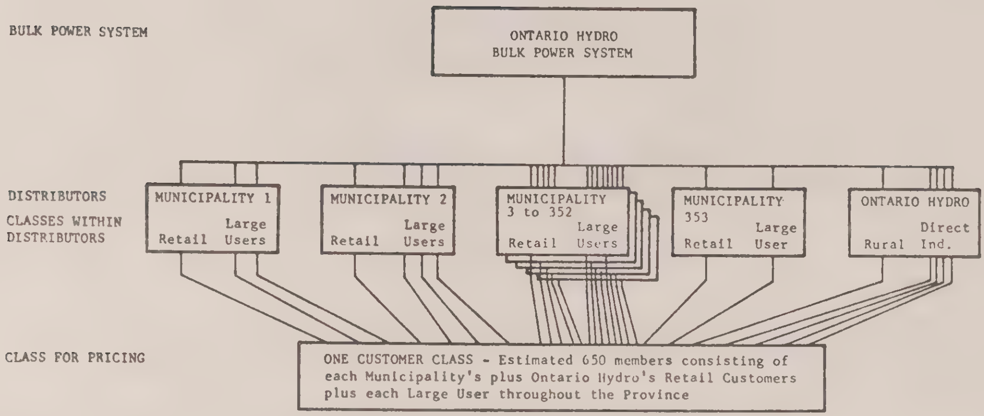
The total costing-load would be arrived at this way:

1. Remove the direct customers' costing-load from the Power District and use the individual direct customers' loads. This means that each direct customer would be costed on the same basis as the retailing utilities. This loss of diversity among the direct customers, and between the rural retail system and the directs, would increase costs for the directs of 16 million dollars.
2. Remove the costing-loads of the large users from the retailing utilities.
3. Add the monthly non-coincident loads of: the 101 large users; the 353 retailing utilities (large users); the rural retail system; and the 100 direct customers.

Since the costing-load of the large-use customers of the retailing utilities would not be included in the utilities' costing-load under the proposed classification, the costs of the new group of large users would be increased by a money total similar to the cost reduction in the utilities' new costing-load. This change would not bring about any measurably significant reallocation of costs.

EXHIBIT VI-1

PROPOSED CUSTOMER CLASS



Electricity Costing and Pricing Study
December 16, 1975

Exhibit VI-2 shows a comparison of class revenues in 1977, excluding the rate modification for the retailing municipal utilities, large users, and the rural retail system. It should be noted that cost data estimates were prepared for the years 1977, 1978, and 1979 based on cost increases over the previous year of 30 per cent, 15 per cent, and 10 per cent in each successive year. All comparisons are for the same delivery conditions at the high-voltage level.

Exhibit VI-3 shows the form of rate structure (excluding marginal costing-charges) for 1977 under the present classification and under the proposed classification. Exhibit VI-4 shows a typical bill calculation under the proposed classification in 1977 for a utility with two large-use customers. The recommended approach would enable smaller utilities to serve larger customers within their boundaries without distorting their own total bills, their customers', or the large users'. At present such distortions may occur when a large user moves from the direct industrial class to a municipal utility.

2. Customer Classes for the Retailing Utility

a. Large Power Users (Load Greater Than 5000 kW)

Large users in a retailing utility, whether customers of a municipal utility or of Ontario Hydro, would be costed in the manner previously described.

b. Remainder of Each Utility's Retail Load (Loads Less than 5000 kW)

A single rate structure would apply to customers comprising the retailing utility's load, large users excepted.

B. PROPOSED PRICE STRUCTURES AND PRICE SCHEDULES AT THE BULK LEVEL

It is recommended that

> *Each bulk customer should receive a three-part charge: (1) a demand charge, (2) a peak energy and off-peak energy charge, and (3) a customer charge.*

This means that the revenue requirement will be divided into the same three components: demand, peak energy and off-peak energy, and customer costs. The unit costs will be developed in the revenue requirement as between demand and energy, peak and off-peak energy, and winter (Oct., Nov., Dec., Jan., Feb., Mar.) and summer (April, May, June, July, Aug., Sept.) seasons by splitting the total revenue requirement by the proportions obtained through marginal costs.[6]

Pricing on the basis of marginal costs will lead to a revenue surplus. This is because the revenue requirement is based on historical accounting-costs, which are lower than the marginal costs of the system. These surplus revenues must be returned to the customer if the revenue requirement is not to be exceeded. Different methods of treating this surplus are proposed for the municipal utilities and the large users. Part of the reason for this is that large-use customers are end users of electricity. It is important for the end user of electricity to face the cost consequences of his decision about use. The marginal price to the end user should be based on marginal cost.

On the other hand, the municipal utilities are distributors, not users, of electricity. The appropriate pricing-method for the cus-

[6]See Volume VII for the results of the marginal cost analysis, and Volume VIII for the use of these results in rate design.

VI-2

COMPARISON OF CLASS REVENUES EXCLUDING RATE MODIFICATION (EST. 1977 BASED ON 30% INCREASE)

	RETAILING MUNICIPAL UTILITIES			LARGE USERS					RURAL RETAIL		
	Demand	Energy	Total	Demand		Energy		Total	Demand	Energy	Total
				Mun	Dir	Mun	Dir				
EXISTING CLASSES											
Cost ($000,000)	607	515	1,122		116		150	266	133	118	251
No. of customers in class			353					100			1
EXISTING CLASSES less diversity											
Cost ($000,000)	542	515	1,107		145		138	283	131	118	249
PROPOSED CLASSES											
Cost ($000,000)	505	432	937	87	145	83	138	453	87	162	249
No. of customers in class			353					201			1

VI-3

FORM OF RATE STRUCTURE (EXCLUDING MARGINAL COSTING CHARGES)

UNDER THE EXISTING CLASSIFICATION FOR 1977 COST ESTIMATES (BASED ON A 30% INCREASE) THE RATES WOULD BE:

- Municipal Utility
  $5.18/kW + .85¢/kWh — kW: monthly non-coincident demand
- Direct Customer
  $4.05/kW + .925¢/kWh — kW: monthly non-coincident demand
- Rural Retail System
  $5.18/kW + .85¢/kWh — kW: monthly non-coincident demand

UNDER THE PROPOSED CLASSIFICATION FOR 1977 COST ESTIMATES (BASED ON A 30% INCREASE) THE RATES WOULD BE:

- All loads - Municipal Utility, Rural Retail System, Large User

  $5.02/kW + .0085/kWh — kW: monthly non-coincident demand

EXHIBIT VI-4

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TYPICAL UTILITY BILL CALCULATION WITH 2 LARGE USE CUSTOMERS
UTILITY LOAD (EXCLUSIVE OF LARGE CUSTOMERS) UNDER THE PROPOSED CLASSIFICATION

Average Monthly Non-coincident Maximum Demand = 470,000 kW
Average Energy = 147,000 GWh

Utility Bill for one month
= (470,000 x 5.02 + 147,000,000 x .0085) + Costing Bill 1 + Costing Bill 2

= ($2,359,400 + 1,249,500) + $100,310 + $212,600

= $3,608,900 + $100,310 + $212,600

Utility would add delivery plus a share of administration and overhead costs to
each Large Use customer's bill.  Hence, bills to Large Use Customer #1, assuming
high voltage supply, would be:

Customer Charge + (10,500 x 5.02) + (5,600,000 x .0085)
= Customer Charge + $100,310


Large Customer #1

  Average Monthly Non-coincident Demand                   = 10,500 kW
  Average Monthly Energy                                  =  5,600 GWh
  Costing Bill #1 = 10,500 x 5.02 + 5,600,000 x .0085 = $100,310

Large Customer #2

  Average Monthly Non-coincident Demand                   = 20,000 kW
  Average Monthly Energy                                  = 13,200 GWh
  Costing Bill #2 = 20,000 x 5.02 + 13,200,000 x .0085 = $212,600
```

tomers of the municipal utilities will be based on the same principles as are used to set prices for the end-user customers at the bulk level.

Ideally, the pricing-rule should apply to both the retailing utilities and their small-use customers. At this time, though, it would be imprudent to introduce such sweeping changes.

For the retailing utilities, two key factors affected this position: administrative costs, and the fact that retailing utilities are not end users of electricity but rather distributors.

The small-use customers of the retailing utilities present a different problem. This group is large, and lacks the sophisticated metering-equipment needed to implement the pricing-rule for large users. Thus considerations of cost (both start-up and administrative) rule out applying the large-use pricing-rule to small users at this time.

Applying the rule to the large-use group above yields maximum benefits with minimum costs. While the large-use group contains few customers, it represents a substantial share of the system's total load.

There are three main areas, then, of pricing-recommendations at the bulk level:

1. The proposed method of assessing the demand charge for retailing utilities and large power users,
2. The proposed pricing-methodology for large users with monthly peak power demands over 5,000 kilowatts, and
3. The proposed pricing-methodology for the municipal utilities.

1. The Proposed Method of Assessing the Demand Charge For Retailing Utilities and Large Power Users

It is recommended that

> *The demand charge assessed to each customer should be based on the customer's monthly non-coincident peak demand in the peak period (0700 to 2300 hours Monday through Friday excluding statutory holidays).*

This method is used as an approximation to peak responsibility. To use the customer's contribution to (say) a 20-minute peak in-

terval of the annual peak day would be self-defeating. Once the day and interval were known, customers could simply adjust their load away from the narrowly defined peak. One of the main lessons of the British experience in peak-versus-off-peak rates was that one must not define peak responsibility too narrowly. In trying to measure peak responsibility, they failed to take account of the customers' ability to shift their loads from one time to another. More specifically, since demand is probably most elastic to time of use, charging all capacity costs to the peak-load users on the basis of a single 20-minute interval on one day in the year would merely shift the peak to another time. In other words, over a large number of hours and days, it is equally probable that the system peak will occur. Hence one must take some care in assessing capacity costs to customers. Monthly non-coincident peak demand in the peak period appears to be the best method of tracking capacity costs. It is recommended that

> *The method of assessing capacity costs should be subject to ongoing analysis, as better cost and load data become available.*

2. Proposed Pricing-Methodology for Large Users with Monthly Peak Power Demands Over 5,000 kW

For large users, rates should be based on marginal costs. The large power users will pay as a class the same unit price, per kilowatt, per peak kilowatt-hour, and per off-peak kilowatt-hour as the retailing utilities. However, the pricing-rule should be to price marginal use at marginal cost. A costing-average would apply to the intra-marginal use. This rule is illustrated later on. In particular, large users would face a fourfold charge.

1. Demand Charge

The demand charge would be based on the marginal costs associated with rate of use. Each customer's demand charge would be based on its monthly non-coincident peak demand during the daily peak period, 0700 hours to 2300 hours Monday through Friday, excluding statutory holidays.

Hence the off-peak period would not carry a demand charge. Loss-of-load probability during the peak period may decline, compared to that of the off-peak period, in response to time-of-day rates; and the costs associated with a potential shortfall in generation from increased load will rise. It is suggested that when these relative prospective costs equal at least ten per cent of the peak-period costs, an off-peak demand charge should be made, based on the large user's non-coincident monthly peak demand in the off-peak period. Since at present these costs are about five per cent, the administrative costs of assessing such an off-peak demand charge outweigh the benefits of a more theoretically pure application of tracking costs.

Furthermore, demand is more likely to exceed capacity in winter (October to March) than in summer (April to September). The demand charge would be higher in winter than in summer, in order to reflect this seasonal cost differential.

2. Peak Energy Charge

The peak energy charge would be based on the marginal costs of providing energy in the daily peak period, Monday through Friday, excluding statutory holidays as well as reflecting seasonal cost variations.

3. Off-Peak Energy Charge

The off-peak energy charge would be based on the marginal costs of providing off-peak energy, 2300 hours to 0700 hours Monday through Friday and 24 hours a day on weekends and statutory holidays.

4. Customer Charge

The customer charge would be based on those costs of serving each customer which do not vary with output. Should the energy and demand components of the rate yield surplus revenues, the customer charge would be adjusted downward

3. Adjusting the Customer Charge for Surplus Revenues

The adjustment to the customer charge would be made in such a way as to ensure that the marginal price the customer paid for kilowatts and kilowatt-hours was based on marginal cost. It is important to preserve the objective of efficiency.[7]

Notionally, one would calculate the credit applied to the customer charge as follows:

1. Determine the surplus for each cost component (peak kWh, off-peak kWh and kW). It would simply equal the difference between marginal unit cost and the costing average-unit cost.
2. Multiply the surplus for each component by the individual customer's use of peak kilowatt-hours, off-peak kilowatt-hours, and kilowatts for three years before the current billing-year. For example, in 1980 the customer's credit for peak kilowatt-hours would be equal to the unit surplus in 1977 times the use of peak kilowatt-hours in 1974. This procedure would be applied to each cost component to arrive at the customer's total credit. In other words, all use would be priced at marginal cost, with the credit for each customer being equal to his base year usage times the component unit surplus. For example, assume a utility sells only peak kilowatt-hours. The 1977 total bill for a customer using this notional approach, would be as follows:

$TB = Mq_1 - sq_o$,

where TB = customer's 1977 total bill,

M = 1977 marginal cost of a peak kWh,

q_1 = customer's 1977 peak kWh consumption,

q_o = customer's 1974 peak kWh consumption, and

s = 1977 unit surplus for peak kWh, which is equal to the difference between the marginal cost (M) and the costing average (A) for peak kilowatt-hours.

As is demonstrated in Volume VIII, the above total bill for 1977 can be reformulated as follows:

$TB = M\Delta q + Aq_o$,

where Δq = the change in the customer's peak kWh consumption between 1974 and 1977, that $q_1 - q_o$

This formulation is the recommended large user pricing rule. It ensures that marginal cost, while base year use is priced at the costing average. The large user pricing rule generates revenues just sufficient to meet the revenue requirement while meeting the efficiency objective. Consequently, the cost of electricity to the large power user group will equal the cost of electricity to a municipality under industrial delivery conditions. The reason for using lagged-use figures is to minimize distortions to the objective of efficiency.

[7]The credit would accrue to a business independently of a change in ownership or location.

The three-year rolling time period reflects an estimate of the limit payback period industry requires for most investments (apart from major plant or locational). The three year payback period is used as an estimator of the criteria used in making the marginal consumption decision.

A separation of less than three years between baseline and current use could lead industry to respond to the baseline rate rather than the marginal price. On the other hand, marginal-cost pricing of growth over more than three years would probably be inconsistent with the principle of continuity in a rate structure.

To sum up, the overriding concern in choosing an appropriate time stretch was to ensure the accuracy of the price signal in a large user's decision-making process, while still setting equal prices for equal use. More importantly, the method of determining the credit would ensure that the marginal use of electricity was priced at its marginal cost.

The following example shows how the pricing-rule for large users would work in practice. The numbers and parameters used are purely illustrative. Consider a small power system with only four customers, where the peak energy component is the only commodity the public utility sells. For illustrative purposes, we shall assume a lag of one year in the pricing-rule; furthermore we shall assume no inflation. The relationship between average and marginal costs for 1977 will then be as follows:

1. 1977 average cost of peak energy = $0.014.
2. 1977 marginal cost of peak energy = $0.021.

The figures for system use for 1976 and 1977 are as follows:

1. 1976 System peak energy = 400,000 kWh.
2. 1977 System peak energy = 440,000 kWh.

The hypothetical system has grown by 10 per cent between 1976 and 1977. The revenue requirement for 1977 is $6,160 (440,000 kWh x $0.014).

If pure marginal-cost pricing were employed, the revenues would be $9,240 (440,000 kWh x $0.021). In other words, there would be a revenue surplus of $3,080 ($9,240 - 6,160).

The pricing-rule for large users avoids surplus revenues. At the same time it ensures that the customer's marginal use is priced at marginal cost. As a first step in determining the large-use rate in the four-customer system one must calculate the unit average costing-rate (UACR). This is found by subtracting the cost of the growth peak kilowatt hours from the 1977 revenue requirement and dividing the result by the 1976 peak use in kilowatt hours. That is:

This 13.3 mills would have been the average cost of a peak kilowatt hour had there been no growth. Thus growth increased the average unit cost of peak energy from 13.3 to 14 mills.

The total bills for 1977 of the four customers are illustrated in the exhibits as described below. For each customer the 1976 and 1977 peak energy use is shown. Given this information and the cost figures discussed above, each customer's total bill is shown: first as it would be under average-cost pricing, and second as it would be under marginal-cost pricing with the proposed large-user pricing-rule.

The case of Customer A is illustrated in Exhibit VI-5. Customer A has reduced his peak energy use by ten per cent. As can be seen, his total bill is less under marginal-cost pricing than under average-cost pricing. That is because his marginal use (that is, the reduced use of 10,000 kWh) is priced at marginal cost. The savings accruing to the system from A's decision are passed on to him.

Customer B, represented in Exhibit VI-6, shows a case where the individual customer's use does not change, while the system grows by 10 per cent. Here B's total bill under marginal-cost pricing is less than it would have been under average-cost pricing.

Customer C, whose peak energy use grew by 10 per cent, (the same rate of growth as the system showed) would pay exactly the same total bill under marginal-cost pricing as under average-cost pricing. This case is shown in Exhibit VI-7.

Exhibit VI-8 shows the case of Customer D, whose peak energy use grew more quickly than that of the system. D's total bill is therefore higher under marginal-cost pricing than it would have been under average-cost pricing. This is because marginal use, that is the growth use of peak energy, is priced at marginal cost.

Finally, Exhibit VI-9 provides a summary of the hypothetical system. It is important to note that the revenues under marginal-cost and average-cost pricing are the same.

Exhibit VI-10 shows the proposed rate schedule for large users for 1977.

4. Proposed Pricing-Methodology for the Municipal Utilities

The municipal utilities are distributors of electrical energy to their end users, and therefore have little chance to respond to price signals. It is recommended that

For the municipal utilities, rates should be based on pro-rated marginal unit costs.

It should be noted, however, that the end use customer of the retail system would have his prices set on the basis of marginal costs. The recommended pricing-guidelines for retail customers will be outlined later.

$$\text{UACR} = \frac{\text{(1977 Revenue Requirement - (Marginal Cost x Growth kWh)}}{\text{1976 Peak Energy}}$$

$$= \frac{\$6,160 - (\$0.021 \times 40,000 \text{ kWh})}{400,000 \text{ kWh}}$$

$$= \$0.0133 \text{ per kWh}$$

EXHIBIT VI-5

CUSTOMER A

1976 PEAK ENERGY 100,000 kWh

1977 PEAK ENERGY 90,000 kWh

AVERAGE COST PRICING

1977 BILL = AVERAGE COST x 1977 USAGE

= $.014 x 90,000 kWh

= $1,260

MARGINAL COST PRICING

1977 BILL = [$.013 x 1976 USAGE] - [MARGINAL COST x REDUCED ENERGY]

= [$.013 x 100,000 kWh] - [$.021 x 10,000 kWh]

= $1,330 - $210

= $1,120

EXHIBIT VI-6

CUSTOMER B

1976 PEAK ENERGY 100,000 kWh

1977 PEAK ENERGY 100,000 kWh

AVERAGE COST PRICING

1977 BILL = AVERAGE COST x 1977 USAGE

= $.014 x 100,000 kWh

= $1,400

MARGINAL COST PRICING

1977 BILL = [$.013 x 1976 USAGE] + [MARGINAL COST x GROWTH kWh]

= [$.013 x 100,000 kWh] + [$.021 x 0 kWh]

= $1,300 + $0

= $1,330

EXHIBIT VI-7

CUSTOMER C

1976 PEAK ENERGY 100,000 kWh

1977 PEAK ENERGY 110,000 kWh

AVERAGE COST PRICING

1977 BILL = AVERAGE COST x 1977 USAGE

= $.014 x 110,000 kWh

= $1,540

MARGINAL COST PRICING

1977 BILL = [$.013 x 1976 USAGE] + [MARGINAL COST x GROWTH kWh]

= [$.013 x 100,000 kWh] + [$.021 x 10,000 kWh]

= $1,330 + $210

= $1,540

EXHIBIT VI-8

CUSTOMER D

1976 PEAK ENERGY 100,000 kWh

1977 PEAK ENERGY 140,000 kWh

AVERAGE COST PRICING

1977 BILL = AVERAGE COST x 1977 USAGE

= $.014 x 140,000

= $1,960

MARGINAL COST PRICING

1977 BILL = [$.0133 x 1976 USAGE] + [MARGINAL COST x GROWTH kWh]

= [$.0133 x 100,000 kWh] + [$.021 x 40,000 kWh]

= $1,330 + $840

= $2,170

EXHIBIT VI-9

SYSTEM SUMMARY

Customer	1976 Energy (kWh)	1977 Energy (kWh)	Average Cost Pricing Revenues $	Marginal Cost Pricing Revenues $
A	100,000	90,000	1,260	1,120
B	100,000	100,000	1,400	1,330
C	100,000	110,000	1,540	1,540
D	100,000	140,000	1,960	2,170
TOTAL	400,000	440,000	6,160	6,160

THUS, 400,000 x $.014 = $6,160 UNDER AVERAGE-COST PRICING

AND

$$[400{,}000 \times \$.0133] + [40{,}000 \times \$.021]$$

$$= \$5{,}320 + \$840 = \$6{,}160$$

UNDER MARGINAL COST-PRICING

WITH THE PROPOSED LARGE-USER PRICING-RULE

EXHIBIT VI-10

1977 LARGE USER RATES

L O A D   P E R I O D

RATE SYSTEM	MONTHLY SUMMER PEAK DEMAND $/kW/Mo.	MONTHLY WINTER PEAK DEMAND $/kW/Mo.	SUMMER PEAK ENERGY ¢/kWh	WINTER PEAK ENERGY ¢/kWh	OFF PEAK ENERGY ¢/kWh
Rates Under Existing Pricing Methodology	4.05	4.05	0.925	0.925	0.925
Rates Using Marginal Costs Pro-Rated to Meet Revenue Requirement	3.255	3.255	1.157	1.157	1.157
Seasonal Time of Day Rates Using Marginal Costs Pro-Rated to Revenue Requirements	0.923	5.532	1.24	1.45	.97
Seasonal Time of Day Rates Using Marginal Costs where Marginal Use (increment or decrement in customer's load) is priced at Marginal Cost	MARGINAL RATE 1.30	MARG.RATE 7.77	MARG.RATE 1.8	MARG.RATE 2.1	MARG.RATE 1.4
	COSTING AVG 0.86	COST.AVG. 5.15	COST.AVG 1.162	COST.AVG. 1.357	COST.AVG. .907

* At 230 kV - FIRM (Other Classes of Power will require corresponding adjustments in rates)

The charge to municipal utilities would have two parts. One part would be for those customers with monthly peak power demands above 5,000 kilowatts. The recommended pricing-methodology for these customers was covered in the previous section. The municipality would assess the marginal costs it incurred in serving these large users (together with a contribution to fixed costs) to the large users themselves.

For the rest of each municipality's load, it is recommended that rates should be based on pro-rated marginal costs. The pro-rated unit costs as between demand and energy, and peak and off-peak energy, would be determined by splitting the total revenue requirement by the proportions obtained through the marginal-cost study. In particular, for the rest of its load each municipal utility would face a fourfold charge.

1. Demand Charge

The demand charge would be based on the pro-rated unit cost associated with rate of use. Each municipal utility's demand charge would be based on its monthly non-coincident peak demand during the daily peak period 0700 hours to 2300 hours Monday through Friday, excluding statutory holidays seasonally adjusted.

2. Peak Energy Charge

The peak energy charge would be based on the pro-rated unit costs of providing energy in the period 0700 hours to 2300 hours, Monday through Friday, excluding statutory holidays seasonally adjusted.

3. Off-Peak Energy Charge

The off-peak energy charge would be based on the pro-rated unit costs of providing off-peak energy, 2300 hours to 0700 hours Monday through Friday and 24 hours a day on weekends and statutory holidays.

4. Customer Charge

The customer charge would be based on the costs associated with serving each municipal utility that do not vary with output.

Exhibit VI-11 shows illustrative rate schedules for municipal utilities for 1977, 1978 and 1979.

One should observe that the proposed pro-rated unit-cost rates reflect the relevant rates of substitution between demand and energy, and between peak and off-peak energy.

Two final observations can be made about the proposed rate structure at the bulk level.

1. It maintains the local autonomy of the municipal utilities.
2. In total, the group of large users pays the pro-rated unit costs. Hence both municipal utilities and large users are costed on an equal basis. At the same time, each large user faces a rate where his marginal use is priced at marginal cost.

The effects of the rate proposals based on marginal costs are shown at the end of this section. Exhibit VI-12 shows a full comparison of revenues under the new classification and the rate proposals at the bulk-power level for 1977. The exhibit also shows what change the rate proposals would make in the demand-energy split.

EXHIBIT VI-12

COMPARISON OF REVENUES
NEW CLASSIFICATION
MARGINAL COSTING (BULK POWER LEVEL)

	RETAILING MUNICIPAL UTILITIES			LARGE USER			RURAL RETAIL		
	Demand	Energy	Total	Demand	Energy	Total	Demand	Energy	Total
EXISTING COSTING METHOD									
Cost ($000,000)	505	432	937	232	221	453	131	118	249
Demand/Energy Split		54/46			51/49 (see Note 3)			53/47	
MARGINAL COSTS PRORATED TO REVENUE REQUIREMENT									
Cost ($000,000)	337	594	931	154	305	459	87	162	249
Demand/Energy Split		36/64			34/66			35/65	
SEASONAL TIME-OF-DAY RATES MARGINAL COSTS PRORATED TO REVENUE REQUIREMENT									
*Costs ($000,000)									
- Winter Peak Hours	293	214	507	129	98	227	80	56	136
- Summer Peak Hours	44	158	202	21	77	98	11	43	54
- Off Peak Hours	-	226	226	-	126	126	-	63	63
	337	598	935	150	301	451	91	162	253
Demand/Energy Split		36/64			33/67			36/64	

Notes:

(1) * Winter Peak Hours: Months-January, February, March, October, November, December
Days-Monday to Friday exclusive of Statutory Holidays
Hours-0700 to 2300

Summer Peak Hours: Months-April, May, June, July, August, September
Days-Monday to Friday exclusive of Statutory Holidays
Hours-0700 to 2300

Off Peak Hours: Remainder of hours in year

(2) Demand charge based on the monthly non-coincident demand.

(3) The existing demand/energy split for the Directs under the present classification and rate structure is 33/67.

EXHIBIT VI-13

FORM OF RATE STRUCTURE WITH SEASONAL TIME-OF-DAY RATES USING MARGINAL COSTS (1977 RATES APPLY)

. MUNICIPAL UTILITY (INCLUDING RURAL RETAIL) PRORATED TO REVENUE REQUIREMENT

	Demand Charge	Energy Charge
Winter Peak Hours	\$5.53/kW	\$.0145 / kWh
Summer Peak Hours	\$ .92/kW	\$.0124 / kWh
Off-Peak Hours	-	\$.0097 / kWh

The above schedule also applies to the total Large User group thereby determining the revenue requirements. However, for individual members of the Large User group the pricing rule is marginal use of marginal cost and intramarginal use at a costing average. Since any increase or decrease in use is charged or rebated at marginal costs then the decision to increase or reduce load is thereby based on marginal costs. Thus, the marginal use is the change in consumption. The increase or decrease in use is calculated on a month-by-month basis on a rolling three-year time lag. The following is the rate schedule.

. LARGE USER IN 1977

	Demand Charge	Energy Charge
Winter Peak Hours	\$5.15/kW$\pm$\$7.77/ΔkW	1.357¢/kWh$\pm$2.1¢/ΔkWh
Summer Peak Hours	\$ .86/kW$\pm$\$1.30/ΔkW	1.162¢/kWh$\pm$1.8¢/ΔkWh
Off-Peak Hours	0	.907¢/kWh$\pm$1.4¢/ΔkWh

kW = non-coincident load in 1974 in the corresponding costing period
ΔkW = increase or decrease in non-coincident load in 1977
kWh = kilowatthour usage in 1974 in the corresponding costing period
ΔkWh = increase or decrease in kilowatthour usage in 1977

EXHIBIT VI-11

ILLUSTRATIVE 1977, 1978, 1979 MUNICIPALITY RATE SCHEDULE

	1977	1978	1979
LOADS			
Winter Demand Charge	\$33.19/kW	\$38.80/kW	\$44.20/kW
Summer Demand Charge	\$ 5.54/kW	\$ 6.47/kW	\$ 7.37/kW
ENERGY			
Winter Peak Charge	1.45¢/kWh	1.68¢/kWh	1.80¢/kWh
Summer Peak Charge	1.24¢/kWh	1.39¢/kWh	1.50¢/kWh
Off-Peak Charge	.97¢/kWh	1.10¢/kWh	1.20¢/kWh

Exhibit VI-13 shows the proposed rate structure in 1977 with seasonal time-of-day rates, using marginal costs for the municipal utilities and the large users.

Given the foregoing rates, Exhibit VI-14 shows a typical bill calculation for a municipal utility with two large-use customers, one that has shown increased growth, and a second that has shown reduced growth.

EXHIBIT VI-14
TYPICAL BILL CALCULATION 1977 RATES

LOAD DATA FOR A TYPICAL WINTER MONTH

(a) UTILITY

Peak Demand	470,000 kW
Peak Energy	130,000,000 kWh
Off-Peak Energy	128,000,000 kWh

(b) CUSTOMER #1

Peak Demand (1974)	10,000 kW
(1977)	12,000 kW
Peak Energy (1974)	2,500,000 kWh
(1977)	3,000,000 kWh
Off-Peak Energy (1974)	3,200,000 kWh
(1977)	3,800,000 kWh

(c) CUSTOMER #2

Peak Demand (1974)	10,000 kW
(1977)	8,000 kW
Peak Energy (1974)	2,500,000 kWh
(1977)	1,800,000 kWh
Off-Peak Energy (1974)	3,200,000 kWh
(1977)	2,600,000 kWh

TOTAL BILL CALCULATION

CUSTOMER #1

(\$5.15 x 10,000 + \$7.77 x 2,000) + (\$.01357 x 2,500,000 + .021 x 500,000) + (\$.00908 x 3,200,000 + \$.014 x 600,000)
= \$67,040 + \$44,425 + \$37,424
= \$148,889

CUSTOMER #2

(\$5.15 x 10,000 - \$7.77 x 2,000) + (\$.01357 x 2,500,000 - .021 x 700,000) + (\$.00907 x 3,200,000 - \$.014 x 600,000)
= \$35,960 + \$19,225 + \$20,624
= \$75,809

UTILITY

(\$5.53 x 470,000 + \$.0145 x 130,000,000 + \$.0097 x 128,000,000) + \$148,889 + \$75,809
= (\$2,599,100 + \$1,885,000 + \$1,241,600) + \$148,889 + \$25,809
= \$5,725,700 + \$148,889 + \$75,809
= \$5,950,398

Exhibit VI-15 shows the percentage shift in class cost allocations for 1977 from the classification change and rate changes.

Finally, Exhibit VI-16 summarizes rate comparisons for 1977, 1978, and 1979 among the municipalities, the large users, and

EXHIBIT VI-15

SHIFT IN CLASS COST ALLOCATIONS* Based on 1977 Cost Estimates	Municipality	Large Users	Rural Retail System
1. Cost Allocation Changes	-0.23%	-2.88%	+1.47%
2. Classification Change	-1.42%	+6.16%	-0.50%
3. Demand Energy Split Based on Marginal Costs	-0.68%	+1.28%	-0.23%
4. Seasonal Time-of-Day Rates Based on Marginal Costs	-0.37%	-1.98%	+1.92%
NET CHANGE	-1.96%	+2.58%	+3.16%

NOTE: FOR PURPOSES OF COMPARISON IT WAS ASSUMED THAT NO CHANGE IN USAGE WOULD OCCUR IN THE LARGE USER GROUP.

* +: increase
-: decrease

the rural retail system. For each group it shows the monthly and annual rates, billed use, and total costs for each of the following cases:

1. Present rate structure and classes,
2. Present rate structure and classes less diversity,
3. Present rate structure and proposed classes,
4. Proposed classes with demand and energy based on marginal costs pro-rated to the revenue requirement, and
5. Proposed classes with seasonal time-of-day rates based on marginal costs pro-rated to the revenue requirement.

C. PROPOSED PRICE STRUCTURES AND ILLUSTRATIVE PRICE SCHEDULES AT THE RETAIL LEVEL

The purpose of the 'flow-through' method of pricing is to ensure that all end use customers receive the proper price signals. That is, to meet the objective of efficiency, the marginal price to the end user must be based on marginal cost.

1. Proposed Rate Structure

A single rate structure would apply to customers that comprised the retailing utility's load without large users. The rate structure would be known as the general rate, and would consist of a threefold charge:

1. Customer Charge

The customer charge would be based on the marginal cost of adding a customer to the municipal system. This cost could be estimated from data on customer accounting; customer services; meter operation; direct services; transformer maintenance expenses; return on meters, transformers, etc.; and those costs of the distributing-system which do not vary with output. If any surplus revenue appeared in the municipality, the surplus attributable to the demand and energy components would be applied as a credit to reduce the customer charge.

While customer costs are a function of several factors, there are two major cost-causing variables which should be singled out: density of customers and type of customers.

Customer density affects costs such as those related to the distributing-system and associated maintenance and operations. Type of customer may affect the type of plant installed. For example, a heavily commercial area may require underground cable rather than overhead lines. These cost differentials should be reflected through subclasses of customers.

In Ontario Hydro's retail system, excluding large users, customers are divided typically into six user groups, whose delivery systems have different cost characteristics.

1. High-density residential (R1),
2. Normal-density residential and single-phase farm (R2 + F2-1),

EXHIBIT VI-16

ELECTRICITY COSTING AND PRICING STUDY
RATE COMPARISONS
1977 (BASED ON 30% INCREASE OVER 1976)

	Municipalities			Large Users					Rural Retail System			Total Cost
	Demand	Energy	Total	Demand		Energy		Total	Demand	Energy	Total	
				From Mun.	From Dir.	From Mun.	From Dir.					
Existing Rate Structure and Classes												
Cost - $000's	606,539	515,228	1,121,767	115,913		150,525		266,438	132,715	117,852	250,567	1,638,772
Billed Usage	9,762 MW	60,615 GWh		2,386 MW		16,273 GWh			2,136 MW*	13,865 GWh		
Annual Rate	62.13 $/kW	8.5 M/kWh		48.58 $/kW		9.25 M/kWh			62.13 $/kW	8.5 M/kWh		
Monthly Rate	5.18 $/kW	8.5 M/kWh		4.05 $/kW		9.25 M/kWh			5.18 $/kW	8.5 M/kWh		
Existing Rate Structure and Classes Less Diversity												
Cost - $000's	591,372	515,228	1,106,600	144,542		138,321		282,863	131,457	117,852	249,309	1,638,772
Billed Usage	9,762 MW	60,615 GWh		2,386 MW		16,273 GWh			2,170 MW	13,865 GWh		
Annual Rate	60.58 $/kW	8.5 M/kWh		60.58 $/kW		8.5 M/kWh			60.58 $/kW	8.5 M/kWh		
Monthly Rate	5.05 $/kW	8.5 M/kWh		5.05 $/kW		8.5 M/kWh			5.05 $/kW	8.5 M/kWh		
Existing Rate Structure and Proposed Classes												
Cost - $000's	505,078	432,148	937,226	86,962	144,542	83,018	138,321	452,903	130,790	117,853	248,643	1,638,772
Billed Usage	8,380	50,841 GWh		1,455 MW	9,774 GWh	2,386 MW	16,273 GWh		2,170 MW	13,865 GWh		
Annual Rate	60.27 $/kW	8.5 M/kWh		60.27 $/kW		8.5 M/kWh			60.27 $/kW	8.5 M/kWh		
Monthly Rate	5.02 $/kW	8.5 M/kWh		5.02 $/kW		8.5 M/kWh			5.02 $/kW	8.5 M/kWh		
Proposed Classes with Demand and Energy Based on Marginal Costs Prorated to Revenue Requirement												
Cost - $000's	336,519	594,311	930,830	58,433	95,811	114,258	190,222	458,724	87,141	162,077	249,218	1,638,772
Billed Usage	8,380 MW	50,841 GWh		1,455 MW	9,774 GWh	2,386 MW	16,273 GWh		2,170 MW	13,865 GWh		
Annual Rate	40.16 $/kW	11.69 M/kWh		40.16 $/kW		11.69 M/kWh			40.16 $/kWh	11.69 M/kWh		
Monthly Rate	3.35 $/kW	11.69 M/kWh		3.35 $/kW		11.69 M/kWh			3.35 $/kWh	11.69 M/kWh		
Proposed Classes with Seasonal Time-of-Day Rates Based on MC Prorated to Rev. Requirement												
Cost - Winter $000's	293,168	213,747		129,010		98,089			80,154	56,228		
- Summer $000's	43,897	157,661		21,015		77,607			10,660	43,031		
- Off Peak $000's	-	225,812		-		125,763			-	62,930		
Total $000's	337,065	597,220	934,285	150,025		301,459		451,484	90,814	162,189	253,003	1,638,772
Billed Usage - Winter	8,833 MW	14,751 GWh		3,887 MW		6,772 GWh			2,415 MW	3,882 GWh		
- Summer	7,927 MW	12,699 GWh		3,795 MW		6,251 GWh			1,925 MW	3,446 GWh		
- Off Peak	-	23,385 GWh		-		13,024 GWh			-	6,517 GWh		
	8,380 MW	50,841 GWh		3,841 MW		26,047 GWh			2,170 MW	13,865 GWh		
Monthly Rate - Winter	5.54 $/kW	14.5 M/kWh		5.54 $/kW		14.5 M/kWh			5.54 $/kW	14.5 M/kWh		
- Summer	.92 $/kW	12.4 M/kWh		.92 $/kW		12.4 M/kWh			.92 $/kW	12.4 M/kWh		
- Off Peak		9.7 M/kWh				9.7 M/kWh				9.7 M/kWh		

* Share of power district costing load

ELECTRICITY COSTING AND PRICING STUDY
RATE COMPARISONS
1978 (BASED ON 30% INCREASE OVER 1977)

	Municipalities			Large Users					Rural Retail System			Total Cost
				Demand		Energy						
	Demand	Energy	Total	From Mun.	From Dir.	From Mun.	From Dir.	Total	Demand	Energy	Total	
Existing Rate Structure and Classes												
Cost - $000's	759,847	605,525	1,365,472	171,491		178,410		349,901	168,626	139,755	308,381	2,023,754
Billed Usage	10,356 MW	63,750 GWh		2,703 MW		18,780 GWh			2,296 MW*	14,711 GWh		
Annual Rate	73.44 $/kW	9.5 M/kWh		58.23 $/kW		10.25 $/kW			73.44 $/kW	9.5 M/kWh		
Monthly Rate	6.12 $/kW	9.5 M/kWh		4.85 $/kW		10.25 $/kW			6.12 $/kW	9.5 M/kWh		
Existing Rate Structure and Classes Less Diversity												
Cost - $000's	739,841	605,625	1,345,466	193,291		178,410		371,701	166,832	139,755	306,587	2,023,754
Billed Usage	10,346 MW	63,750 GWh		2,703 MW		18,780 GWh			2,333 MW	14,711 GWh		
Annual Rate	71.51 $/kW	9.5 M/kWh		71.51 $/kW		9.5 M/kWh			71.51 $/kW	9.5 M/kWh		
Monthly Rate	5.96 $/kW	9.5 M/kWh		5.96 $/kW		9.5 M/kWh			5.96 $/kW	9.5 M/kWh		
Existing Rate Structure and Proposed Classes												
Cost - $000's	624,456	500,393	1,124,849	116,269	193,291	105,232	178,410	593,202	165,948	139,755	305,755	2,023,754
Billed Usage	8,779 MW	52,673 GWh		1,635 MW	11,077 GWh	2,703 MW	18,780 GWh		2,333 MW	14,711 GWh		
Annual Rate	71.13 $/kW	9.5 M/kWh		71.13 $/kW		9.5 M/kWh			71.13 $/kW	9.5 M/kWh		
Monthly Rate	5.93 $/kW	9.5 M/kWh		5.93 $/kW		9.5 M/kWh			5.93 $/kW	9.5 M/kWh		
Proposed Classes with Demand and Energy Based on Marginal Costs Prorated to Revenue Requirement												
Cost - $000's	411,930	703,174	1,115,104	77,381	126,825	147,872	250,713	602,791	109,470	196,389	305,859	2,023,754
Billed Usage	8,779 MW	52,673 GWh		1,649 MW	11,077 GWh	2,703 MW	18,780 GWh		2,333 MW	14,711 GWh		
Annual Rate	46.92 $/kW	13.35 M/kWh		46.92 $/kW		13.35 M/kWh			46.92 $/kW	13.35 M/kWh		
Monthly Rate	3.91 $/kW	13.35 M/kWh		3.91 $/kW		13.35 M/kWh			3.91 $/kW	13.35 M/kWh		
Proposed Classes with Seasonal Time-of-Day Rates Based on MC Prorated to Rev. Requirement												
Cost - Winter $000's	359,009	258,483		170,872		130,767			100,761	69,383		
- Summer $000's	53,746	183,333		27,828		99,716			13,390	51,180		
- Off Peak $000's	-	265,337		-		163,994			-	75,955		
Total $000's	412,755	707,153	1,119,908	198,700		394,477		593,177	114,151	196,518	310,669	2,023,754
Billed Usage - Winter	9,253 MW	15,345 GWh		4,404 MW		7,763 GWh			2,597 MW	4,119 GWh		
- Summer	8,305 MW	13,175 GWh		4,300 MW		7,166 GWh			2,069 MW	3,678 GWh		
- Off Peak	-	24,153 GWh		-		14,928 GWh			-	6,914 GWh		
	8,779 MW	52,673 GWh		4,352 MW		29,857 GWh			2,333 MW	14,711 GWh		
Monthly Rate - Winter	6.47 $/kW	16.8 M/kWh		6.47 $/kW		16.8 M/kWh			6.47 $/kW	16.8 M/kWh		
- Summer	1.08 $/kW	13.9 M/kWh		1.08 $/kW		13.9 M/kWh			1.08 $/kW	13.9 M/kWh		
- Off Peak	-	11.0 M/kWh		-		11.0 M/kWh			-	11.0 M/kWh		

* Share of power district costing load

EXHIBIT VI-16

ELECTRICITY COSTING AND PRICING STUDY
RATE COMPARISONS
1979 (BASED ON 10% INCREASE OVER 1978)

	Municipalities			Large Users					Rural Retail System			Total Cost
	Demand	Energy	Total	Demand		Energy		Total	Demand	Energy	Total	
				From Mun.	From Dir.	From Mun.	From Dir.					
Existing Rate Structure and Classes												
Cost - $000's	871,517	688,422	1,559,939	207,324		215,187		422,511	197,271	161,815	359,086	2,341,536
Billed Usage	10,837 MW	65,564 GWh		2,984 MW		20,494 GWh			2,453 MW*	15,411 GWh		
Annual Rate	80.42 $/kW	10.5 M/kWh		64.33 $/kW		11.25 M/kWh			80.42 $/kW	10.5 M/kWh		
Monthly Rate	6.70 $/kW	10.5 M/kWh		5.36 $/kW		11.25 M/kWh			6.70 $/kW	10.5 M/kWh		
Existing Rate Structure and Classes Less Diversity												
Cost - $000's	847,691	688,422	1,536,113	233,414		215,187		448,601	195,007	161,815	356,822	2,341,536
Billed Usage	10,837 MW	65,564 GWh		2,984 MW		20,494 GWh			2,493 MW	15,411 GWh		
Annual Rate	78.22 $/kW	10.5 M/kWh		78.22 $/kW		10.5 M/kWh			78.22 $/kW	10.5 M/kWh		
Monthly Rate	6.52 $/kW	10.5 M/kWh		6.52 $/kW		10.5 M/kWh			6.52 M/kWh	10.5 M/kWh		
Existing Rate Structure and Proposed Classes												
Cost - $000's	708,493	560,049	1,268,542	141,569	128,373	232,125	215,187	717,254	193,925	161,815	355,740	2,341,536
Billed Usage	9,108 MW	53,338 GWh		1,820 MW	12,226 GWh	2,984 MW	20,494 GWh		2,493 MW	15,411 GWh		
Annual Rate	77.79 $/kW	10.5 M/kWh		77.79 $/kW		10.5 M/kWh			77.79 $/kW	10.5 M/kWh		
Monthly Rate	6.48 $/kW	10.5 M/kWh		6.48 $/kW		10.5 M/kWh			6.48 $/kW	10.5 M/kWh		
Proposed Classes with Demand and Energy Based on Marginal Costs Prorated to Revenue Requirement												
Cost - $000's	486,698	770,044	1,256,742	97,243	159,243 176,447	176,447 159,243	295,933	729,088	133,217	222,489	355,706	2,341,536
Billed Usage	9,108 MW	53,338 GWh		1,820 MW	12,226 GWh	2,984 MW	20,494 GWh		2,493 MW	15,411 GWh		
Annual Rate	53.44 $/kW	14.44 M/kWh		53.44 $/kW		14.44 M/kWh			53.44 $/kW	14.44 M/kWh		
Monthly Rate	4.45 $/kW	14.44 M/kWh		4.45 $/kW		14.44 M/kWh			4.45 $/kW	14.44 M/kWh		
Proposed Classes with Seasonal Time-of-Day Rates Based on MC Prorated to Rev. Requirement												
Cost - Winter $000's	424,314	280,915		214,897		153,296			122,653	77,757		
- Summer $000's	63,492	200,578		34,974		117,926			16,293	57,859		
- Off Peak $000's	-	293,030		-		196,539			-	87,013		
Total $000's	487,806	774,523	1,262,329	249,871		467,761		717,632	138,946	222,629	361,575	2,341,536
Billed Usage - Winter	9,600 MW	15,589 GWh		4,862 MW		8,507 GWh			2,775 MW	4,315 GWh		
- Summer	8,616 MW	13,357 GWh		4,746 MW		7,853 GWh			2,211 MW	3,853 GWh		
- Off Peak	-	24,392 GWh		-		16,360 GWh			-	7,243 GWh		
	9,108 MW	53,338 GWh		4,804 MW		32,720 GWh			2,493 MW	15,411 GWh		
Monthly Rate - Winter	7.37 $/kW	18.0 M/kWh		7.37 $/kW		18.0 M/kWh			7.37 $/kW	18.0 M/kWh		
- Summer	1.23 $/kW	15.0 M/kWh		1.23 $/kW		15.0 M/kWh			1.23 $/kWh	15.0 M/kWh		
- Off Peak	-	12.0 M/kWh		-		12.0 M/kWh			-	12.0 M/kWh		

* Share of power district costing load

3. High-density intermittent occupancy (R3),
4. Normal-density intermittent occupancy (R4),
5. General with distribution voltage supply, including three-phase farms (G + F2-3), and
6. General with sub-transmission voltage supply (T + G special).

The general class is subdivided between customers supplied at distribution and at subtransmission voltage levels, to reflect the fact that customers at subtransmission voltage do not contribute to the cost of transformation to distribution voltage levels, or to the cost of the distribution voltage system.

Any change in these subclasses should be based on empirical studies.

2. Demand Charge

All customer loads over 50 kilowatts would face a demand charge. This demand charge would reflect the marginal costs of the generating and high-voltage facilities. It would also reflect the marginal cost of subtransmission and distributing facilities dependent on the transformation and voltage conditions of supply to the customer. The demand charge would be based on the customer's monthly non-coincident peak demand.

3. Energy Charge

There would be an energy charge for the first 10,000 kilowatt-hours of use per month, reflecting the marginal energy costs of generation and marginal losses of the delivery system. The relevant marginal demand costs associated with the first 50 kilowatts of load would be added to the marginal energy costs, based on the coincident demand (relative to the demand of the retailing utility) of the group of all customers whose load is less than 50 kilowatts. This would meet the agreed criterion of continuity in a rate schedule that moves from a pure energy rate to a twofold rate. A second block (of say 990,000 kilowatt-hours per month) would reflect only the marginal energy costs of generation with marginal losses as appropriate to the point of delivery. The end rate would be adjusted to co-ordinate with the large-use group. At present, resource cost-benefit analysis does not clearly justify time-of-use rates for this customer class.[8]
The costs of new metering may outweigh the expected benefits from time-of-use rates. However, the results are close.

Two-rate metering of residential load would make it possible to apply time-of-day marginal rates, which should provide an incentive to reduce peak load and so in the long run reduce capital requirements.

An economic comparison of single and two-rate metering in Ontario to 1995 indicates that the costs of fully carrying out two-rate metering outweigh the expected savings. The potential benefits would be only slightly reduced, however, and the costs would be minimized, if two-rate meters were offered optionally.

With the present cost of storage heating and estimated customer elasticities, the anticipated rate differential would probably not induce a significant peak reduction. Nevertheless, two-rate metering may benefit some customers with large off-peak consumption. Moreover, having peak-versus-off-peak residential rates available optionally would provide incentive to develop combination heating-systems, or other technologies.

An optional rate would be a threefold rate: customer charge, peak energy charge (0700 hours to 2300 hours, Monday through Friday), and off-peak energy charge (2300 hours to 0700 hours, Monday through Friday, and 24 hours a day on weekends and statutory holidays). The marginal cost of capacity would be folded into the peak energy charge.

2. Customer Charge and Surplus Revenues

The revenue surplus accruing to kilowatt-hour use up to 10,000 kilowatt-hours would be determined by multiplying the component surplus by the use. The credit for each customer (to be applied to the customer charge) would then be determined by dividing the total surplus by the total number of customers in the class. Similarly, the surplus accruing to demand and energy for those customers with an average monthly use of more than 50 kilowatts would be calculated. Then the credit for each customer (to be applied to the customer charge) would be determined by dividing this surplus by the number of customers in this use group.

A hypothetical example may usefully illustrate the flow-through method of pricing the small-use customers of retailing utilities. As was shown, this pricing-approach gives the end user the correct price signal in the form of rates based on marginal costs. There are no surplus revenues, and the rate-structure proposals do not interfere with the local automony of the municipalities.

This example of the flow-through pricing-method is based on the following:

1. The utility system has a revenue requirement of $1,000,000.
2. The costs of the bulk-power system account for eighty per cent of the revenue requirement, or $800,000.
3. The local costs are twenty per cent of the revenue requirement, or $200,000.
4. There are 2200 yearly-billed customers who all make up a single class.
5. The total yearly-billed sales are 45,000,000 kWh and 53,000 kW.
6. The total marginal energy cost is 1.7 cents a kWh, which is the sum of the marginal bulk energy cost (1.4 cents a kWh) and the marginal distribution energy cost (.3 cents a kWh).
7. The marginal demand cost is $2.90 a kW, which is the sum of the marginal bulk demand cost ($2.60 a kW) and the marginal distribution demand cost (30 cents a kW).
8. Customer costs are estimated to be $4.50 a month.

If prices were based purely on the marginal cost of production, the utility would gain the revenues shown in the accompanying Table:

45,000,000 kWh	@	1.7¢ per kWh	=	$ 765,000
53,000 kW	@	$2.90 per kW	=	$ 153,700
2,200 customers x 12 months x $4.50			=	$ 118,800
TOTAL REVENUES				$1,037,500

[8]The cost benefit study for residential time-of-use rates is in Appendix 6 of Volume 8

However, since revenue requirement of the utility is $1,000,000, pure marginal-cost pricing would yield a revenue surplus of $37,500 from pure marginal cost pricing. The flow-through approach removes the surplus by reducing the customer charge to the end user. In this way, the integrity of price signal in the energy rate will be maintained, while the utility will just meet its revenue requirement. The reduction in the customer charge is a credit calculated as follows:

$37,500/(2200x12)=$1.42 a month.

The customer charge then becomes $3.08 a month ($4.50 - $1.42). The total billed revenue for the utility would therefore be

45,000,000 kWh	@	1.7¢/kWh	=	$ 765,000
53,000 kW	@	$2.90/kW	=	$ 153,700
2,200 x 12 x $3.08			=	$ 81,300
TOTAL BILLED REVENUE				$1,000,000
= REVENUE REQUIREMENT				$1,000,000

The importance of the flow-through approach is that it ensures the customer's decision to consume a little less electricity, or a little more, is based on the marginal costs of production and delivery. The revenue requirement is met by adjusting the customer charge, with only minimal distortions to the allocation of resources devoted to producing electricity.

Exhibit VI-17 summarizes the illustrative marginal-cost-based rates and their effect on former class revenues the rural retail system and selected municipalities for 1977, 1978, and 1979.

Exhibit VI-18 shows how the illustrative rates would affect a rural residential and general-class customer's bill in 1977, 1978, and 1979, as compared to the total bill for those years under the present rate structure. As can be seen, the low user pays less under the proposed schedule, with marginal-cost pricing, than he would under the present one. At the same time, the higher user pays more. Moreover the frugal user, indeed all users, have a greater incentive to reduce their use of electricity.

3. Comparison with the Present Rate Structure

The present rate schedule is a declining-block energy rate. This rate form played a key part in the electrification of Ontario, and induced what was called the downward cost-price spiral. At that time, the greater use of electricity allowed the utility to take advantage of economies of scale in large plant facilities. Economies of scale led to lower marginal unit costs of production, which led in turn to lower prices. However, the period of decreasing costs is over. The declining-block energy-rate structure is out of step with increasing electricity costs. The number of blocks used, the interval size between blocks, and the height of each block is somewhat judgemental.[9]

Under the proposed rate schedule, all uses would be priced at the same energy rate, based on the marginal cost of electricity. There would be no special rates for different types of electrical use (for instance, water heaters).

Under the present schedules the rates of the municipal utilities' lack uniformity, although that partly stems from impact problems in raising end rates. The total bill for 1,000 kilowatt-hours' use depends upon where a residential customer lives. Indeed, there is a substantial difference between the lowest and highest bill for the same use per month. Under the proposals presented here, these rate differentials would be reduced. The energy charge would tend to be more uniform throughout the province. The energy charge for all customers would be based on those costs which vary with the amount of electricity produced. However, differentials would remain in the customer charge, owing to the local cost considerations of each electric utility. These reflect the utility's policy on contributed capital, the ratio of its debt to its equity, the type of service it renders, customer density, and so on.

4. Summary of Recommendations

The recommendations may be summarized as follows:

1. *For purposes of allocating bulk-power costs, there should be a single class of customers comprising all retailing utilities (including Ontario Hydro's Rural Retail System) plus all large industrial, commercial, or institutional users of electricity.*
2. *Initially, large users should be defined as customers whose monthly peak load is 5000 kilowatts or more; but this level should be lowered to 3000 kilowatts as soon as load data can be gathered and analysed.*
3. *At the bulk level, the revenue requirement should be determined from a cost allocation based on pro-rated marginal-cost unit costs. Pro-rated unit costs should be developed as between demand and energy, and peak and off-peak energy, by splitting the total revenue requirement by the proportions obtained through marginal costs.*
4. *Large power users should face a four-part charge:*

a. *A demand charge based on the marginal capacity costs associated with rate of use in the peak period. The winter peak demand charge would be higher than the summer peak demand charge, to reflect seasonal cost differentials.*

b. *A peak energy charge based on marginal running-costs associated with providing energy in the daily peak period. The winter peak energy charge would be higher than the summer peak energy charge to reflect seasonal cost differentials.*

c. *An off-peak energy charge based on marginal running-costs associated with providing energy in the off-peak periods.*

d. *A customer charge based on the costs associated with serving each customer that do not vary with output.*

[9]The justification is based on the shape of the customer's demand curve, not on costs as is popularly conceived.

SUMMARY OF THE ILLUSTRATIVE MARGINAL COST-BASED RATES FOR THE RURAL RETAIL SYSTEM

MONTHLY CUSTOMER CHARGE

Class	1977	1978	1979
R1	$3.50	$4.00	$4.50
R2 & F2-1	$4.00	$4.50	$5.00
R3	$6.00	$6.75	$7.50
R4	$6.75	$7.50	$8.25
G & F2-3	$8.00	$8.50	$9.00
T & G9 Special	$15.00	$18.00	$20.00

Above Customer Charges plus the following Monthly Rates:

Kilowatt Charge

First 50 kW	N/C		
Balance - per kW	$3.30	$3.80	$4.60
Subtransmission voltage allowance	$0.35	$0.40	$0.50
3-phase transformer allowance			
up to 49.9 kV	$0.25	$0.25	$0.25
50 kV and above	$0.50	$0.50	$0.50

Energy Charges

1st 10,000 kWh -¢/kWh	2.94	3.29	3.65
Next 990,000 kWh -¢/kWh	1.58	1.71	1.80
All additional kWh-¢/kWh	1.15	1.32	1.43

EFFECT OF PROPOSALS ON RETAIL CLASS REVENUES

RURAL RETAIL SYSTEM

$'000

1977	REVENUE BASED ON EXISTING PRICING METHOD	REVENUE BASED ON EXISTING PRICING METHOD	% CHANGE
R1	97,683	97,535	-0.15
R2 + F1	147,916	146,335	-1.08
R3	11,852	11,031	-7.44
R4	16,559	15,972	-3.68
G + F2 - 3	88,413	89,009	+0.67
T + G Special	38,479	41,350	+7.46
1978			
R1	118,848	116,834	-1.72
R2 + F1	176,019	172,780	-1.87
R3	14,168	13,095	-8.19
R4	19,620	18,746	-4.66
G + F2 - 3	101,052	104,255	+3.17
T + G Special	45,704	49,848	+9.07
1979			
R1	142,472	138,602	-2.79
R2 + F1	206,414	201,608	-2.38
R3	16,698	15,397	-8.45
R4	23,090	21,766	-6.08
G + F2 - 3	115,884	121,181	+4.57
T + G Special	53,924	59,998	+11.26

SUMMARY OF ILLUSTRATIVE MARGINAL COST-BASED RATES - MUNICIPAL UTILITIES

MONTHLY CUSTOMER CHARGES

	1977		1978		1979	
	Residential	General	Residential	General	Residential	General
(1) Acton	1.75	3.75	2.50	5.70	2.95	6.00
(2) Belleville	.75	1.75	1.50	3.00	.30	1.00
(3) Elora	.65	1.25	1.00	1.65	3.00	6.60
(4) Mount Brydges	.30	.90	.70	1.50	.20	.75
(5) North York	1.95	4.50	1.85	4.75	2.00	5.85
(6) Oakville	2.40	5.35	2.85	6.75	4.25	7.10
(7) Ottawa	2.25	5.50	4.00	8.45	1.70	5.00
(8) Vaughan Twp.	.90	2.60	3.75	6.75	1.75	5.00

Above Customer Charges plus the following Monthly Rates

Utilities	(1), (2), (4), (7)	(1), (2), (4), (7), (8)	(1)(2)(3)(4)(7)(8)
Demand 0-50 kW	N/C	N/C	N/C
over 50 kW-per kW	$2.90	$3.25	$4.05
sub-transmission allowance	$0.30	$0.35	$0.45
Energy			
1st 10,000 kWh/Mo-¢/kWh	2.59	2.80	3.21
Next 990,000 kWh/MO-¢/kWh	1.40	1.46	1.58
All additional kWh/Mo-¢/kWh	1.15	1.32	1.43

Utilities	(3), (5), (6), (8)	(3), (5), (6)	(5), (6)
Demand 0-50 kW	N/C	N/C	N/C
over 50 kW-per kW	$3.10	$3.55	$4.25
sub-transmission allowance	$0.30	$0.35	$0.45
Energy			
1st 10,000 kWh/Mo	2.79	3.06	3.36
Next 990,000 kWh/Mo	1.50	1.59	1.65
All additional kWh/Mo	1.15	1.32	1.43
3-Phase transformation allowance			
up to 49.9 kV	$0.25/kW	$0.25/kW	$0.25/kW
50 kV and above	$0.50/kW	$0.50/kW	$0.50/kW

Exhibit VI-17

EFFECT OF PROPOSALS ON RETAIL CLASS REVENUES - SELECTED MUNICIPAL UTILITIES

	1977			1978			1979		
	Existing Method	Proposed Method	% Change	Existing Method	Proposed Method	% Change	Existing Method	Proposed Method	% Change
Residential									
Acton	477,907	507,922	+6.28	520,204	563,561	+8.33	631,100	648,077	+2.69
Belleville	2,488,126	2,657,752	+6.82	2,695,018	2,962,317	+9.92	3,034,202	3,211,005	+5.83
Elora	208,613	207,094	-0.07	229,284	229,561	+0.12	256,357	256,539	+0.07
Mount Brydges	87,859	90,952	+3.52	96,836	100,233	+3.51	109,571	111,852	+2.08
North York	29,625,457	29,548,046	-0.03	32,998,712	31,979,459	-3.19	36,145,057	35,068,112	-3.07
Oakville	5,523,261	5,642,114	+2.15	6,167,001	6,235,456	+1.11	7,040,753	7,090,302	+0.70
Ottawa	21,912,859	24,622,489	+12.37	25,172,823	28,339,720	+12.58	28,367,938	29,321,643	+3.36
Vaughan Twp.	1,983,105	1,978,735	-0.02	2,111,318	2,224,068	+5.34	2,297,414	2,336,449	+1.70
General									
Acton	646,622	616,729	-4.85	712,488	669,129	-6.48	780,942	764,123	-2.20
Belleville	4,067,393	3,898,783	-4.32	4,492,302	4,224,600	-6.34	4,936,690	4,760,608	-3.70
Elora	163,247	164,766	+0.09	181,530	181,265	-0.15	194,284	194,110	-0.09
Mount Brydges	46,172	43,210	-6.85	50,481	47,059	-7.27	55,349	53,055	-4.32
North York	53,050,298	53,154,765	+0.20	57,125,091	58,141,717	+1.78	62,698,045	63,771,469	+1.71
Oakville	6,000,698	5,881,788	-2.02	6,551,749	6,482,457	-1.07	7,129,292	7,078,829	-0.71
Ottawa	45,452,875	42,758,994	-6.30	49,558,978	46,394,478	-6.82	53,069,339	52,138,129	-1.79
Vaughan Twp.	2,602,998	2,607,096	+0.16	2,827,014	2,714,716	-4.14	3,089,629	3,049,363	-1.32

Exhibit VI-18

EFFECT OF PROPOSALS ON INDIVIDUAL RETAIL CUSTOMER BILLS

RURAL

RESIDENTIAL CLASS

1R1 (High Density)

kWh/Mo	1977 Existing	1977 Proposed	% Change	1978 Existing	1978 Proposed	% Change	1979 Existing	1979 Proposed	% Change
250	15.50	10.85	-30.00	17.75	12.23	-31.10	20.25	13.63	-32.69
750	27.65	25.55	-7.59	31.25	28.68	-8.22	35.00	31.88	-8.91
1,000	33.53	32.90	-1.88	37.88	36.91	-2.56	42.38	41.01	-3.23
2,000	57.03	62.30	+9.24	64.38	69.81	+8.43	71.88	77.51	+7.83

1R2 (Standard Density)

250	16.88	11.35	-32.76	19.25	12.73	-33.87	21.75	14.13	-35.03
750	29.13	26.05	-10.57	32.75	29.18	-10.90	36.50	32.38	-11.29
1,000	35.01	33.40	-4.60	39.38	37.41	-5.00	43.88	41.51	-5.40
2,000	58.51	62.80	+7.33	65.88	70.31	+6.72	73.38	78.01	+6.31

GENERAL CLASS

Distribution Voltage Level

75 kW

7,500	308.38	311.00	+0.85	321.25	350.25	+9.01	351.38	397.75	+13.20
15,000	447.13	463.50	+3.66	466.00	518.00	+11.16	520.13	579.00	+11.32
30,000	649.63	700.50	+7.83	691.00	774.50	+12.08	775.13	849.00	+9.53

300 kW

60,000	1765.63	1917.00	+8.57	1876.00	2142.50	+14.21	2027.63	2424.00	+19.55
90,000	2170.63	2391.00	+10.15	2326.00	2655.50	+14.17	2537.63	2964.00	+16.80
120,000	2575.63	2865.00	+11.23	2776.00	3168.50	+14.14	3047.63	3504.00	+14.97

Sub-Transmission Voltage Level

1,000 kW (Hydro-owned transformers)

200,000	5904.73	6096.00	+3.24	6216.00	6808.00	+9.52	6717.63	7675.00	+14.25
400,000	8604.73	9256.00	+7.57	9216.00	10226.00	+10.96	10117.63	11275.00	+11.44

4,000 kW (customer-owned transformers)

800,000	22184.63	23426.00	+5.60	23816.00	26266.00	+10.29	25817.63	29775.00	+15.32
1600,000	31864.63	33486.00	+5.09	35816.00	37606.00	+5.00	39417.63	41175.00	+4.46
2000,000	36704.63	38086.00	+3.76	41816.00	42886.00	+2.56	46217.63	48375.00	+4.67

Rate impact constraints were not applied to the marginal cost rates in order that the total bill differences would be noted.

5. *For the large power users rates should be such that marginal use would be priced at marginal cost.*

6. *For municipal utilities, rates should be based on pro-rated marginal costs.*

7. *Each municipal utility's charge should have two parts. One part would be for customers with average monthly loads of more than 5000 kilowatts. For the rest of its load, each municipal utility would face a fourfold charge:*

a. *A demand charge, based on pro-rated unit cost associated with rate of use in the peak period.*

b. *A peak energy charge, based on pro-rated unit costs associated with providing energy in the peak period.*

c. *An off-peak energy charge, based on pro-rated unit costs associated with providing energy in the off-peak periods.*

d. *A customer charge, based on the costs associated with serving each municipal utility that do not vary with output.*

8. *The marginal costs that a municipal utility incurred in serving large users (with a contribution to fixed costs) should be assessed to the large user.*

9. *Customers of retailing utilities should be priced on the basis of marginal production and delivery costs.*

10. *A single rate structure should apply to all customers of a retailing utility taking less than 5000 kilowatts a month. This charge would be threefold.*

a. *A customer charge, based on the marginal cost of adding a customer to the municipal system. Surplus revenue from marginal-cost pricing of demand and energy would be used to reduce the customer charge.*

b. *All customer loads greater than 50 kilowatts would face a demand charge, to reflect the marginal costs of the generation and high-voltage common facilities, and the marginal costs of subtransmission and distribution facilities, depending on the transformation and voltage conditions of supply to the customer. The demand charge would be based on the customer's monthly non-coincident peak demand.*

c. *An energy charge, consisting of the first 10,000 kilowatt-hours of use per month, reflecting the marginal energy costs of generation and marginal losses of the delivery system. The relevant marginal demand costs associated with the first 50 kilowatts of load would be added to the marginal energy costs. A second block would reflect only the marginal energy costs of generation plus marginal losses as appropriate at the point of delivery. The end rate would be adjusted to coordinate with the large-use group.*

11. *The present practice of having a minimum bill should be phased out in all retailing utilities, and in its place a customer charge be adopted that would not include any consumption of kilowatt-hours.*

12. *Flat-rate billing for electric water heaters should be phased out.*

13. *The current practice of converting individually metered apartments to bulk metering should be discontinued.*

14. *The current practice of bulk-metering new apartment buildings should cease, and individual meters should be installed for each dwelling-unit.*

15. *Apartment buildings originally designed for individual meters, and now serviced with bulk meters, should be reconverted to individual meters for each dwelling-unit.*

16. *The metering status of the remaining apartment buildings originally designed to accommodate bulk metering, and requiring structural changes, should be determined from cost-benefit analysis conducted by the appropriate municipality.*

VII. PRICING-PROPOSAL FOR INTERRUPTIBLE POWER SERVICE

A. VALUE OF INTERRUPTIBLE POWER

Interruptible or curtailable power may be defined as electric service of lower reliability than firm power service, in that it may be interrupted during conditions of system emergency (defined as inadequate total capacity, inadequate energy capability, and inadequate operating-reserves), in order to maintain a high degree of reliability of service supply to users of firm power.

Ontario Hydro presently offers two types of interruptible power, designated as Class A and Class B, and two types of scheduled power, designated as Class C and Valley-Hour.[10]

Very briefly, Class-A interruptible power enables Ontario Hydro to reduce the amount of generating-capacity it would otherwise need to provide, through being able to interrupt the Class-A load whenever capacity is inadequate to supply firm loads. Besides providing savings in generating-capacity, Class-B interruptible power lets Ontario Hydro make operating-economies by lowering the total costs of providing the needed operating-reserves. Scheduled Class-C power is available to industrial customers who are willing to reduce their load on a daily schedule of restricted hours, with resulting savings to Ontario Hydro in meeting daily system peaks. Scheduled Valley-Hour power is available for use between 11:00 p.m. and 7:00 a.m. daily throughout the year.

1. Value of Interruptible Power to Ontario Hydro

Because it can be interrupted, this type of power enables Ontario Hydro to reduce the amount of generating capacity it would otherwise need to provide, and therefore interruptible power is offered at a discount from the firm-demand rate. To better appreciate the role of interruptible power and its value, one must understand the planning-concepts for its supply.

Three areas are important for planning interruptible power: load forecasts, system planning, and operational planning.

Load Forecasts

In load forecasting, the estimates of firm load are made by subtracting the estimated load reduction one can achieve by cutting all interruptible loads from the total estimated primary load.

The estimate of the amount of interruptible load reduction that can be achieved is based on the difference between the total loads of the interruptible customers at the time of the system peak in December and the firm portion of their contracts. Such calculations have been made for more than ten years, and the resulting amount of available interruptible load reduction comes to approximately two thirds of the sum of the customers' non-coincident interruptible loads. It is therefore assumed that on the average, approximately two thirds of the total load specified as interruptible in the contracts is available for cutting at the time of the system peak.

System Planning

From a system-planning point of view, there is no difference between interruptible Class A and Class B, because both these classes are excluded from the planning-requirements for peak-generation resources. Interruptible load is considered as being supplied from the system's generation reserve capacity. However, the energy sales are included for determining the plant mix in the generation planning-process. In planning transmission and transformation facilities, interruptible load is considered as firm load, since those facilities must be able to supply the total primary load; however, interruptible load can be cut in local transmission and transformation emergencies.

Operational Planning

From an operational point of view, interruptible loads are a kind of available capacity, in that cutting the loads has the same effect on available reserve capacity as increasing capacity. One important difference between the two is that whereas the system operator has precise information on the status of capacity, he does not know with the same precision how much interruptible load he has available for cutting at any moment. At the present time, though, his knowledge is accurate enough for operating purposes. The estimated amount of interruptible load available for cutting is based, in part, on the previous month's experience. Load data is examined, and the individual interruptible loads at the time of the monthly peak are used as a guide.

While large-use customers use interruptible power like firm power, at the same time it forms part of Ontario Hydro's system reserve. The operating reserve, which is part of the system reserve, is insurance against a system failure at least equal in magnitude to a first major-contingency fault. A fuller description of system reserve can be found in Volume IX. Without interruptible power, more generation capacity would be needed.

2. Long and Short-Run Benefits of Supplying Interruptible Power

In the long run, interruptible power would save Ontario Hydro the cost of generation equal to the load which would otherwise be firm, with the corresponding reserve margin needed to support the firm load. Under present conditions it is hard to determine the appropriate level of interruptible power, because of lack of knowledge of the customers valuation of the relative price-risk relationship between firm and interruptible power.

Without interruptible power, both planned system capacity and planned reserves would be higher; and therefore savings have been realized for all customers based on deferred generation at the time of the forecast. Savings will occur for all customers only if the load forecast recognizes the amount of interruptible load in time for it to be incorporated into system-expansion plans. It follows that one can attribute savings in generating capacity not installed to those customers who committed themselves to interruptible power in an earlier planning-period, and those savings have no direct connection with loads that actually occur.

3. Savings in Generating-Capacity

These are savings from a reduction in the generation capacity required. They are possible because of Ontario Hydro's right to curtail the supply of interruptible power. Several factors have to be taken into account in assessing the value of the capacity savings, such as diversity among customers, customers permitted to convert to firm power on short notice, additional administrative costs, and savings in system reserve.

Since interruptible power is useful mainly to reduce peak load at times of system emergency, one can conclude that its worth should be related to the cost of the marginal plant, that is, the cost of peaking-capacity. Both interruptible A and B loads contribute equally to savings in generating-capacity.

4. Operating-Savings

Besides contributing to savings in generating-capacity, Class-B loads form part of the operating reserve, and are available for cutting within ten minutes. Operating-savings are therefore real-

[10] Volume Nine provides a full description and definitional background of interruptible power and the current offerings. See Appendix I in particular, on the definitions of the various types of service.

ized in the form of reduced generation held in the form of ten-minute pickup reserve. Class-B loads can also be used at present to defer starting-up of combustion turbine units or using water in less efficient hydraulic plants. Since the savings from using interruptible B power in the latter way are insignificant, it is therefore recommended that this practice should be discontinued.

On the basis of the study, it is recommended that in future Ontario Hydro should make available to its large-use customers two types of interruptible power: one, designated Class 1, with a higher risk, to be used as ready reserve as well as for system emergencies; and a second, designated Class 2, with a lower risk, to be used for system emergencies only, subject to thirty minutes' notice for interruption.

5. Value of Interruptible Power to Ontario Industry

The users of interruptible power today (heavy industry and large companies) enjoy cost savings amounting to between ten and sixteen per cent on a per-kilowatt basis, depending upon supply voltage and load factor.

Firm power provides electrical service at a certain cost with high reliability. Interruptible power, however, provides electrical service at a lower cost than firm, but with a greater chance of curtailments or cuts. In theory, at least, if interruptible power were marketed efficiently and in accordance with Ontario Hydro's pricing-objective, a customer taking it would trade off savings against the costs of less reliable power.

B. SUPPLY CONDITIONS FOR INTERRUPTIBLE POWER

1. Minimum Amount for Interruptible Contract

No doubt a lower minimum would increase the number of users; but as long as customers receive notice to cut their loads by telephone (as they do now), the lower the minimum amount, the more customers Ontario Hydro has to notify in order to obtain the reduction in load it requires. Therefore, until a more automatic cutting-procedure can be instituted, it is recommended that the 5000-kW minimum be retained.

2. Availability of Interruptible Load When Required

Interruptible customers cannot be relied upon to have their contract demand always available for cutting when required. The study team considered whether customers should be required to guarantee to cut some minimum amount of load when asked to. The problem with such a requirement is that either the customer's load must be above the firm contract demand by the guaranteed amount at the time of system stress, or the customer must be required to cut some of his firm load. To overcome the problem of identifying customers using interruptible load at the time of need, an automatic load-information transmittal system, such as telemetering, is recommended for all customers with interruptible loads.

3. Entering and Leaving Interruptible Contracts

At present customers can switch to firm power on relatively short notice, which compares unfavourably with the much longer period of from six to ten years that Ontario Hydro needs to install new generating-facilities. Hence, in practice these conditions cannot ensure savings in generation. Some continuity and consistency in contracts is needed for purposes of future planning. Having customers move in and out of interruptible contracts distorts planning and policy decisions. It is concluded that a five-year committment would provide adequate stability to the planning-process. While customers would be allowed to switch to firm power, the interruptible contract would require that under system emergency conditions (which require cutting firm loads), those that had left the interruptible market without providing five years notice would be subject to cuts ahead of other firm-load customers for five years.

4. Length and Frequency of Interruptions

Certain industrial processes can withstand frequent but short interruptions, others less frequent but longer ones, while certain loads can be interrupted with less notice than others. It has been claimed that the maximum interruptions allowed under Ontario Hydro's present contracts expose customers to unreasonable risk. Since it is desirable to encourage greater use of interruptible power in the future, it is necessary to make a trade-off between what customers feel to be an unreasonable duration for interruptions and marketability of the product. It is therefore recommended that the maximum-interruption terms of the present contracts should be relaxed somewhat, to provide for cutting five days a week, with maximum cuts of five hours a day from March to November inclusive and ten hours a day from December to February inclusive. Maximum cuts should also be limited to two a day, ten per cent of the hours in any month, and ten per cent of the hours in any year, subject to change as required to meet changing system conditions.

5. Schedule-C and Valley-Hour Power

Under a pricing-methodology incorporating time-of-use rates, the present conditions of supply for these types of power will no longer be appropriate. For example, the present restricted period of five hours for Class-C loads would not match the proposed daytime peak price period of sixteen hours. (The proposed nighttime offpeak price period of eight hours would, however, coincide with the hours when valley-hour power is available now.) Since at present there are only 2 scheduled C contracts and no customers taking valley-hour power, it is recommended that in 1978 Ontario Hydro should discontinue offering these classes of scheduled power.

6. Future Sales of Interruptible Power

With limited capital available, the current surplus of generating capacity will fall sharply over the next few years. It is estimated that there may be a shortfall in reserve generation beginning in the winter of 1979-80. Hence the study group has concluded that Ontario Hydro should actively promote further sales of interruptible power beginning in 1979 or sooner, depending on the actual loads for 1976 and 1977.

C. PRESENT PRICING-SYSTEM FOR INTERRUPTIBLE POWER

Interruptible power brings savings to Ontario Hydro. The benefits of interruptible power cannot be realized without both the power system and the interruptible-power customers. The sharing of this saving is the inducement for the customer and utility to continue such service.

In considering the method of pricing interruptible power, the study group reviewed the advantages and disadvantages of the present system. These are summarized as follows:

a. Advantages of the Present Pricing-System

1. The calculation of the discount is relatively straightforward.

2. Customers have become familiar with the current system.
3. Customers only have to decide whether they want interruptible power at a fixed discount. They need not consider varying price-risk alternatives.

b. Disadvantages of the Present Pricing-System

1. There is little theoretical or operational justification for sharing the generation savings 50-50 between firm and interruptible customers in the present price structure.
2. Attaching a fixed discount to interruptible power based on sharing the savings can lock out potential customers. There may be potential customers who would buy interruptible power at a discount greater than the established fixed one, but still less than the maximum allowable discount that reflects the incremental cost of additional service. This currently untapped market would add more to interruptible revenues than to interruptible costs.
3. While potentially restricting entry to the interruptible market, the present pricing-system also arbitrarily profits those customers for whom a set discount more than adequately covers the costs of expected interruptions.
4. Given that savings accrue to the Corporation when interruptible power is sold, a pricing-system such as the present one does not reap the greatest possible benefits from this type of service.

Given these drawbacks to the present approach to interruptible power, a number of alternative pricing and marketing-models for the supply of interruptible power were examined. The details of the alternatives which were examined and rejected are described in Section IV of Volume IX and its appendices.

D. RECOMMENDED APPROACH TO PRICING

1. Method of Assessing the Value of Interruptible Power

The maximum worth of interruptible power can be equated to displaced generation. The utility saves at least the annualized capital and operating-cost of peaking-capacity. The only cost of supplying such load is the cost of fuel plus the cost of transmission and transformation plus a share of operating, maintenance, and administrative expense. For the present and in the medium term, conventional fossil-fuelled, steam-electric units are expected to fill the role. In recent years, the fixed capacity discount for interruptible power has been based on the annualized cost per kW of the Lennox GS with allowances for diversity, administrative costs, reserves, etc., and a 50-50 sharing of the benefits. However, in the long run, the cost of fossil fuels and the uncertainty of their supply make the planning-process somewhat cloudy. Hence the type of generation to be displaced in the future will be different.

Therefore it is recommended that

> ***The capacity component of the discount for interruptible power should be based on the annualized cost of capacity as determined by the marginal cost study; that is, the generation-plant component of the demand charge.***

2. Pricing-Process

An open-market choice process is recommended for pricing interruptible power in the future. This is deemed consistent with the objective of allocating the resources used to produce electricity efficiently. An open-market choice process is analogous to a progressive open auction in which competitive bidding is practiced.

An auction solves specific resource-allocation problems. Given that a fixed amount of interruptible power must be parcelled out to a variable number of customers, there are innumerable pricing-methods. However, only a competitive pricing-scheme can efficiently allocate this fixed supply among bidding customers so as to achieve maximum net social benefits after cost. To spare both the customers and Ontario Hydro sharp dislocations as they change from one pricing-system to another, it is recommended that

> ***Beginning in 1979, all potential customers for interruptible power should be offered interruptible power at a fixed discount off the firm-power demand rate before the beginning of a calendar year; and any interruptible supply not sold then should be offered to customers through an open-market choice process.***

The proposed Ontario Hydro auction of interruptible power may be briefly described as follows:

a. Preparation

1. A certain level of interruptible power would be made available for sale, based on the requirements of system planning and operations and on certain other considerations.
2. A distribution of joint probabilities of interruption in terms of frequency and duration (five-year time period) would be estimated and supplied for the interruptible supply. The auction approach is contingent on the availability of this information. This is necessary so that the customer should be capable of determining the expected costs to him associated with various levels of risk. Without such data, the auction approach would be infeasible.
3. Interruptible power would first be offered on a fixed discount basis. No estimate of probability of interruption would be provided; but information would be provided on limits of interruption. The reason for this would be that the blocks of interruptible power sold at a fixed discount would rank with those sold by auction. Therefore, depending on where the fixed discount stood compared to discount derived from the market, the probabilities of interruption could fall anywhere along the distribution curve.
4. Any remaining interruptible supply would then be put up for auction sale.
5. Before the sale, the final piece of information given to potential participants would be the floor price for interruptible power, which would reflect the total firm-power demand charge less the generation component of the demand charge. The value of the generation component would reflect (after diversity is taken into account) the maximum possible discount available to the customer.

b. Operation

The theme of the auction would be that the purchasers who were willing to pay the most for their interruptible power would receive it with relatively high degrees of reliability. The lower the bid, the lower the degree of reliability or the higher the chance of interruption, compared to the highest bidder.

The only constraint binding the participant would be that once a bid is entered, it could not be lowered. Any bid could be withdrawn or raised at any time.

c. Results

At the end of the auction, all bids would be ranked from highest to lowest, to the point where the available supply of Class-2 and Class-1 interruptible power was exhausted or until the floor price for interruptible was reached. It must be stressed that the blocks of Class-2 and Class-1 power sold under a fixed discount before the auction would be ranked with the bidders as well. Those purchasers of interruptible power who had a discount lower than the fixed rate would have more reliable interruptible supply than those who opted for the traditional pricing-system. Naturally, the opposite would hold for customers with a discount greater than the fixed amount.

E. RELEVANCE OF THE RECOMMENDED PRICING-SYSTEM TO ONTARIO HYDRO

The open-market choice process should assist in reaching an optimal allocation of interruptible power. The purchaser would decide for himself how much interruptible power to buy and what price to pay for it. Moreover, if demand for interruptible power should exceed supply, available interruptible power would be allocated solely within the market system.

Thus the system would present a floor price for interruptible power that reflected Ontario Hydro's marginal cost for providing the service.[11]

Furthermore, for any given level of reliability for the product, each customer would have upper bounds upon the price he was willing to pay. These upper limits would reflect the marginal cost (savings) to the customer of purchasing interruptible power. The discounts for interruptible power would fall within these limits.

This system would provide a policy continuum within which any demand for interruptible power would be efficiently allocated. For example, if demand for the service were much greater than supply, equilibrium prices for interruptible power would tend towards the upper price limit. On the other hand, if the supply of interruptible power were considerably greater than the demand, then discounts could tend towards Ontario Hydro's floor price for interruptible power. Either way, the bidding-system would maximize the possible benefits of using interruptible power.

F. RELEVANCE OF THE RECOMMENDED PRICING-SYSTEM TO THE CUSTOMER

Because the recommended pricing-system is based on a free-market allocation through an auction process, the user of interruptible power will only buy if the option is better than the one he could have under fixed-price interruptible or firm power. The natural substitutability between firm and interruptible power would probably cause an individual company's demand for the latter to be price elastic.

Furthermore, preliminary analysis suggests that the open-market choice process will be useful, as a tool for long-range supply planning.

The recommendations resulting from the study are summarized below:

1. *In 1978, Ontario Hydro should base the fixed discounts for interruptible power on a fixed sum of dollars, based on deferred generation planned in 1973 and the forecasted billing kW for 1978 according to the official load forecast for 1978.*
2. *In 1978, Ontario Hydro should discontinue using Class-B interruptible power to effect daily economy savings.*
3. *Ontario Hydro should offer its large-use customers two types of capacity interruptible power: one, designated Class 1, with a higher risk, to be used as ready reserve as well as for system emergencies; and a second, designated Class 2, with a lower risk, to be used for system emergency conditions only, subject to thirty minutes' notice, to conform with system requirements for slow-pickup reserve.*
4. *The minimum contract amount should remain at 5000 kW until some more practical form of notification for load cutting and measurement can be introduced.*
5. *An automatic transmittal system for load information, such as telemetering, should be installed, to provide the system control centre with totalized load data for all loads of customers taking interruptible power.*
6. *Any customer that switches from interruptible to firm power, without providing five years' notice, should be subject to interruption during the next five years ahead of any other firm customer, if cuts in firm load become necessary; and the amount of load subject to cutting should equal the customer's maximum interruptible load in the previous five years. Furthermore, the cutting order should be chronologically based: that is, those customers that most recently left interruptible contracts should be cut ahead of other designated customers. Moreover, failure to cut on request should incur a surcharge of 50 per cent on the firm demand rate for the amount of load designated as interruptible.*
7. *Interruptible power contracts should provide for cutting five days a week, Monday to Friday, with maximum cuts of five hours a day from March to November inclusive and 10 hours a day from December to February inclusive. Maximum cuts should also be limited to two a day, 10 per cent of the hours in any month, and 10 per cent of the hours in any year, subject to alteration as required to meet changing system conditions.*
8. *In 1978 Ontario Hydro should discontinue offering both scheduled power Class C and Valley-Hour power, and offer the present Class C customers the choice of converting to either firm power or interruptible power Class 1 or Class 2.*
9. *Interruptible power should be offered to large-use customers of municipal utilities under the same terms and conditions that apply to direct customers of Ontario Hydro.*
10. *In offering interruptible power for sale, Ontario Hydro should provide the customer with estimates of the probable frequency and duration of interruptions for a five-year period.*
11. *In 1979 Ontario Hydro should begin actively promoting the sale of more interruptible power,*

[11]The floor price or maximum discount would be based on the marginal capacity cost of a marginal plant. This measure most accurately reflects the savings in generation that Ontario Hydro would obtain by offering interruptible power.

with the aim of selling a further 100 contracted MW of both Class 1 and Class 2 interruptible power in each of the years 1980 to 1982, to provide the system with approximately 300 effective MW of interruptible power Class 1 as ready reserve and 500 effective MW of interruptible power Class 2 as slow-pickup reserve by 1982. Furthermore, if actual firm demand in 1976 and 1977 exceeds the forecasts by a significant amount, consideration should be given to advancing active promotion of further sales of interruptible power.

12. *The formulae shown in Appendix V of Volume IX should be adopted for establishing a fixed discount for interruptible power, but the capacity component of the discount should be based on the annualized cost of capacity as determined by the marginal-cost study: that is, the generating-plant component of the demand charge.*

13. *Beginning in 1979, all potential interruptible power customers should be offered interruptible power Class 1 and Class 2 at a fixed discount off the firm power demand rate before the start of a calendar year; and any interruptible power supply not sold should then be offered to customers through an open-market choice process.*

14. *The open-market choice (auction) sales of interruptible power should be conducted as described in this study, with all the constraints and clauses as there specified.*

VIII. CONSIDERATIONS OF IMPACT

In recommending a major policy change in the pricing of electricity, it is important to consider the potential effects of the change. Generally, the purpose of an impact statement is to provide information about the direct and indirect effects of the costing and pricing-recommendations. It is a study of the social, economic, environmental, and organizational consequences of increasing rate levels and altering rate structures.

Assuming a fixed revenue requirement, any changes in the rate structure itself mean that some customers will pay more and some less. This result is inevitable in moving to a price structure where prices reflect marginal costs rather than embedded average costs. And here is where impact analysis plays an important role. It is an analysis of the various effects of the pricing-proposals on these customer groups. Impact analysis is meant to give some guidance about both when to make rate changes and how far to alter the rate structure. Moreover, it is meant to uncover non-financial effects, such as social and environmental ones.

This overview of the impact considerations deals with three main topics: (1) The meaning of impact studies, (2) The methodology of impact studies, and (3) A summary statement of the impact study results. The full impact study will be found in Volume X.

A. THE MEANING OF IMPACT STUDIES

The study of impacts is meant to go beyond merely examining the obvious or intended effects of rate change. For example, the 1974 annual report of the U.S. Council on Environmental Quality linked the usefulness of impact statements to the exploration and understanding of secondary effects of a policy change. This class of studies involves analysing the *interaction* of the various effects of changing such matters of policy as rate levels and rate structures. Of necessity, the approach must be interdisciplinary, developing and using suitable tools for situations where little data is available and the nature of relationships of variables is so complex and little understood that usual mathematical modelling is not practical. Broadly speaking, this approach to studies of policy impact is called "technology assessment".

Historically, the concept of technology assessment is linked to political and social developments in North America in the middle and late 1960s. It was during this period that society as a whole became aware of the cumulative effects of technological developments set in train many years earlier. While it is no part of this study to describe these events, it remains true that from the early 1960's onward, society became collectively more conscious of issues such as the decay of cities and the pollution of the environment. In short, they became conscious of a certain deterioration in their "quality of life". Rightly or wrongly, the blame for much of the blight was laid at the doors of the large public and private institutions which, it was claimed, implemented their technologies without duly considering possible adverse effects in the future. It was in the context, then, of this increased social concern that technology assessment was developed to aid the decision-making process.

Although technology assessment is still in an embryonic stage of development, it can be described in general terms. The Science Council of Canada has set forth a useful definition

> *Technology assessment is defined as an activity to provide information about, and systematic analyses of, the internal and external consequences (short, medium and long term) for a society of the application and diffusion of a technolo- gical capability into its physical, social, economic and political systems. This information and systematic analysis is to be so structured and presented as to aid the decision makers charged with the responsibility of operating those systems.*[12]

Impact studies are not new; Ontario Hydro has previously studied the site impact of generating-stations at Bruce and elsewhere, as well as the choice of transmission corridors. This study, instead of assessing the impacts of a physical project such as a plant, has assessed the impact of a change in price and pricing-policy. In applying the tools of technology assessment to major policy decisions rather than to technological change, it represents an innovative effort, not only within Ontario Hydro, but also in Canada and the United States.[13]

B. THE METHODOLOGY OF IMPACT STUDIES

Certain descriptions of impact analysis give the impression that one has at one's disposal a new procedure for assessing the consequences of a technological application or a policy change. At present, impact analysis is an art as well as a science. At the same time, several types of systematic analyses have become part and parcel of impact analysis. Two of these types of systematic analyses are: cost-benefit analysis and futures research.

Each activity implied in cost-benefit analysis and futures studies is meant to help the decision maker in evaluating a given policy change. The type of information each activity ideally intends to provide is outlined below.

Cost-Benefit Analysis

The traditional tool for evaluating any major program, technological or other, has been cost-benefit analysis. Historically, it is true to say that economic considerations have formed the basis of much executive decision-making in both the public and private sectors. Unfortunately, the range of possible consequences which can be quantified in economic terms is restricted. Economic cost-benefit analysis may therefore be considered a useful but limited tool for assessing policy impact. This tool is being enlarged to take account of non-economic secondary effects.

Futures Studies

Futures studies go further in their attempts to outline the full range of consequences of policy changes. Futures research includes such diverse activities as socio-economic forecasting, economic projections, market analysis, corporate planning and technological forecasting. Futures research is generally taken to include the projection of present trends into the future, simulation or modelling of future events or of the state of society at some future date, and long-range planning for organizations, institutions, or societies. The most widely used technique for accomplishing this task is scenario writing. Future studies are especially useful when the effects of a policy take place more than two or three years in the future: that is, when conditions may be unlike those of today. Scenario writing refers to describing a possible state of future events; the description may or may not be developed historically.

Given this overview, it is possible to outline briefly the impact study which the electricity costing and pricing study undertook.

[12] *A Technology Assessment System*, Science Council of Canada Background Study No 30, March 1974.

[13] The application of technology assessment to policy impacts was first explicitly developed by Selwyn Enger in a paper titled "Technology Assessment: A no-fault automobile insurance policy for the U.S.".

Both internal and external resources were used to develop the impact study. The external resource was Hittman Associates Inc. of Columbia, Maryland, a group with considerable experience and expertise in technology assessment and impact analysis.

In conducting this study, two main rate-structure scenarios were developed.

Scenario A was much the same rate structure as Ontario Hydro had in 1975, with some modifications. This rate structure was then projected to 1978 and 1983, with a virtual doubling of rates.

In Scenario B, the revenue requirement was projected again to 1978 and 1983. But important policy changes were incorporated into the alternative rate structure, such as a demand-energy split based on marginal costs of demand and energy, time-of-day rates, etc. Actual marginal cost-based rates obtained near the conclusion of the study differ significantly in some ways from the rates of Scenario B. Nevertheless, the direction and approximation of the impacts of Scenario B rates may not differ greatly from the impacts of the rates based on marginal cost. Recalculations were made where refinements in impact assessment were deemed necessary.

As part of the impact study, Hittman Associates designed these two alternative rate-structure scenarios and analysed their effects. The Hittman study consisted of three basic steps after the development of the two alternative rate structures.

First, the alternatives were presented to the chief organizations in Ontario that take an interest in utility rates but lie outside the actual rate-making and approval process. These various interested parties were questioned about their positions and reaction towards the rate proposals. Exhibit VIII-1 provides a summary of their responses to the scenario concepts.

Second, Hittman did a series of case studies. These were selected from industrial, commercial, institutional, and residential customers of the Ontario electric-utility system. A municipal utility buying power wholesale from Ontario Hydro was also included. Interviews were held with both management and technical personnel representing each subject of the case study. In this way, information was gained about the potential impacts, short-term and long-term, of the alternative rate structures for each case.

Finally, impact models were constructed to symbolize the expected actions and reactions in response to rate change identified during this study. These models were meant to provide an overview of the potential social and economic effects of changing the pricing-policy for electricity in Ontario. These models are what one may describe as first-generation impact models. They provide no more than a starting-point from which further work may be done. Exhibit VIII-2 shows an impact model assessing the doubling of bulk-power revenue by 1978, while Exhibit VIII-3 is an impact model assessing changes in pricing-policy.

The case studies and impact models that Hittman Associates developed have been integrated with the impact work conducted by Ontario Hydro personnel.

One feature of this impact study is that it gave an opportunity for groups affected to participate in the project before it was a complete and finished product. Thus, impacts should be monitored as the accepted recommendations come into effect. Such ongoing analysis will allow:

1. The continuation of case-study and sectoral analysis, as well as impact model-building and forecasting (such as forecasting electricity rates in other jurisdictions);
2. The control of intended impacts and objectives as against actual impacts;
3. The discovery of unintended impacts not covered in this report;
4. The measure of the magnitude of the various impacts (e.g., conservation), which are directionally indicated in the studies to date; and
5. The improvement and refinement of impact methodology.

C. SUMMARY STATEMENT OF RESULTS OF IMPACT STUDY

1. Short-Run Impacts

In the short run to 1980, there will be few negative impacts to employment attributable to pricing of electricity. There may be localized exceptions concentrated in the abrasives industry. Customers are expected to have little or no difficulty in adjusting to changes in rate structure. In fact, discussions with representatives of industry suggest that replacing much of the flexibility used in ratemaking with well defined objectives such as efficiency, and therefore concrete criteria, may be to them more important than an initial shift of some costs from municipalities to large industrial customers. A reason for this position may be that large users are more likely to realize the benefits of their own future conservation efforts under a marginal-cost pricing-system than under the criteria employed in an average-cost pricing-system. Moreover, such a conservation saving would not have the perverse effect of shifting costs to other groups of customers.

Under rates based on marginal cost, the customer heating his dwelling with electricity also remains in a fairly good position as against users of oil and gas heating. However, his bill would be higher than it would have been if the declining energy blocked average rate methodology were retained. If all dwellings were insulated to OEL standards, the proportional cost advantage of oil and gas heating over electric would be much less by 1979 than it was in 1975. The reason for the more severe effect on residential costs is that between 1975 and 1979 the average of all energy costs rises by a factor of over 2-1/2, yielding in some cases a figure of $1,000 a year. Using rates based on *average cost*, the all-electric home becomes relatively less expensive than before in comparison with other energy sources. This would shift even more new homes to electric heating and so increase the potential shortfall of generation. The customer using electric space-heating might be able to reduce the impact of his bill further if optional time-of-day pricing were available. This will occur if statistical sampling showed that the space-heating load uses more kilowatt-hours per off-peak hour than per peak hours.

A negative impact, in the short run, is the change in outlook, procedure, and equipment local utilities would need to make to convert back to a policy of individual metering for multi-family dwellings.

However, during the first three years, the new large customer does not share in the benefits of historical investment. Volume VIII has simulated the electricity bills for fifteen present large customers using marginal-cost pricing. Some of them are increasing their use of electricity, and some are conserving. Large

EXHIBIT VIII-1
RESPONSES OF PARTIES AT INTEREST TO SCENARIO CONCEPTS

Scenario Concepts / Parties at Interest	Scenario A	Scenarios A&B	Basic Scenario B			Sensitivity Concepts for Scenario B				
	Maintain Existing Rating Structure	Increase Bulk Rates Amounting to Revenue Doubling in 3 Years	Modify Demand/Energy Split to Achieve 35/65 Ratio	Establish Uniform Provincial Demand and Energy Rates	Establish Discretionary Customer Charge Allowing Municipal Utilities to Meet Revenue Requirements	Provide Peak/Off-Peak Rates For Large Users: Non-Coincident Peak Demand Measured Between 700 and 2300 Hours	Provide Peak/Off-Peak Rates For Large Users: .15¢/Kwh Peak-Off-Peak Price Differential	Change Peak Demand Measurement From 20 Minutes to One Hour	Prohibit Master (bulk) metering in Multi-Family Dwellings	Interruptible Service Based Upon Tendered Bid and Probability of Interruption
'Association of Major Power Consumers of Ontario	mixed; position on existing structure depends on the nature of alternative structure	moderately opposed, favors sizeable rate increase but feels that revenue doubling is excessive	opposed; disagrees with methodology used to justify 35/65 ratio	favors in principle	uncertain	highly favorable believes this can offer savings to some industries and also help curb demand	favors in principle but not sure if differential is adequate	favors in principle	favors in principle	mixed; favors principle of expanding interruptible service but uncertain if this is best method
**Association of Municipal Electric Utilities	mixed; position on existing structure depends on the nature of alternative structure	favors; necessary for adequate maintenance and expansion	favors in principle; uncertain about modifying all the way to 35/65 ratio	favors in principle	favors in principle; wants clarification on how derived and on municipality discretion in establishing customer classes	favorable but uncertain over ability to achieve load improvement		favors in principle	mixed; recognize consumer demand for individual meters but fearful of costs, especially bad debts	favors in principle
**Consumers Association of Canada, Ontario Provincial Association	mixed, favors elimination of rate inequities, but opposed to centralized utility decision-making	opposes; prefers non-voluntary checks on demand	favors over present situation but prefers 50/50 D/E split	mixed; for reasons cited under 1st column	favors in principle	highly favorable but unconvinced that peak/off-peak energy rates cannot be offered economically to small users		uncertain	highly favorable	conditionally favors; wants reserve margin reduced
*Energy Probe	mixed, favors elimination of rate inequities, but opposed to centralized utility decision-making	uncertain on size of increase, favors using rates to discourage consumption	favors in principle	mixed; for reasons cited under 1st column	uncertain	highly favorable but unconvinced that peak/off-peak energy rates cannot be offered economically to small users		opposes	highly favorable	favors in principle
**Ontario Municipal Electric Association	unavailable for comment	generally? favors substantial rate increase if necessary to maintain current debt/equity ratio and service expansion plans	unavailable for comment	unavailable for comment	unavailable for comment	unavailable for comment		unavailable for comment	unavailable for comment	unavailable for comment
°Sierra Club of Ontario	opposes; desire to have electricity bills reflect usage patterns of individual consumers	uncertain on size of increase; favors using rates to discourage consumption	favors in principle	highly favorable	uncertain	highly favorable but unconvinced that peak/off-peak energy rates cannot be offered economically to small users		initially, opposed, presently uncertain	highly favorable	conditionally favors; uncertain of tendered bid aspect; wants reserve margin reduced
'Urban Development Institute Ontario	no formal opinion	no formal opinion	no formal opinion	no formal opinion	no formal opinion	favors in principle		no formal opinion	highly favorable; raised prospect that this might encourage developers to "no electric"	no formal opinion

*Intervenor Before Ontario Energy Board on Rate Hearings in 1974
**Intervenor Before Ontario Energy Board on Rate Hearings in 1974 and 1975
'Non-Intervenor
°Derived solely from 1975 testimony

EXHIBIT VIII-2

IMPACT MODEL = DOUBLING OF BULK POWER REVENUES BY 1978

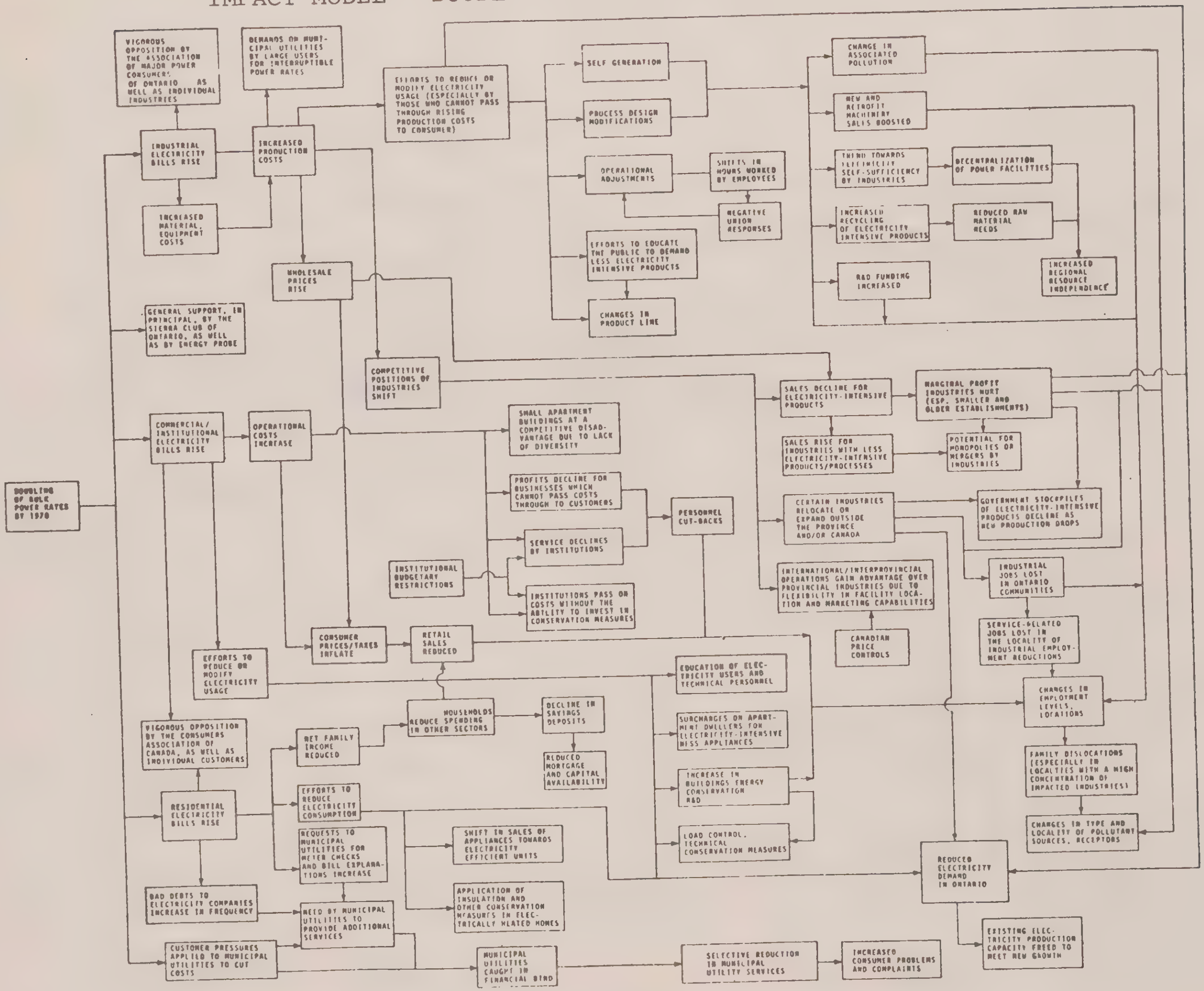
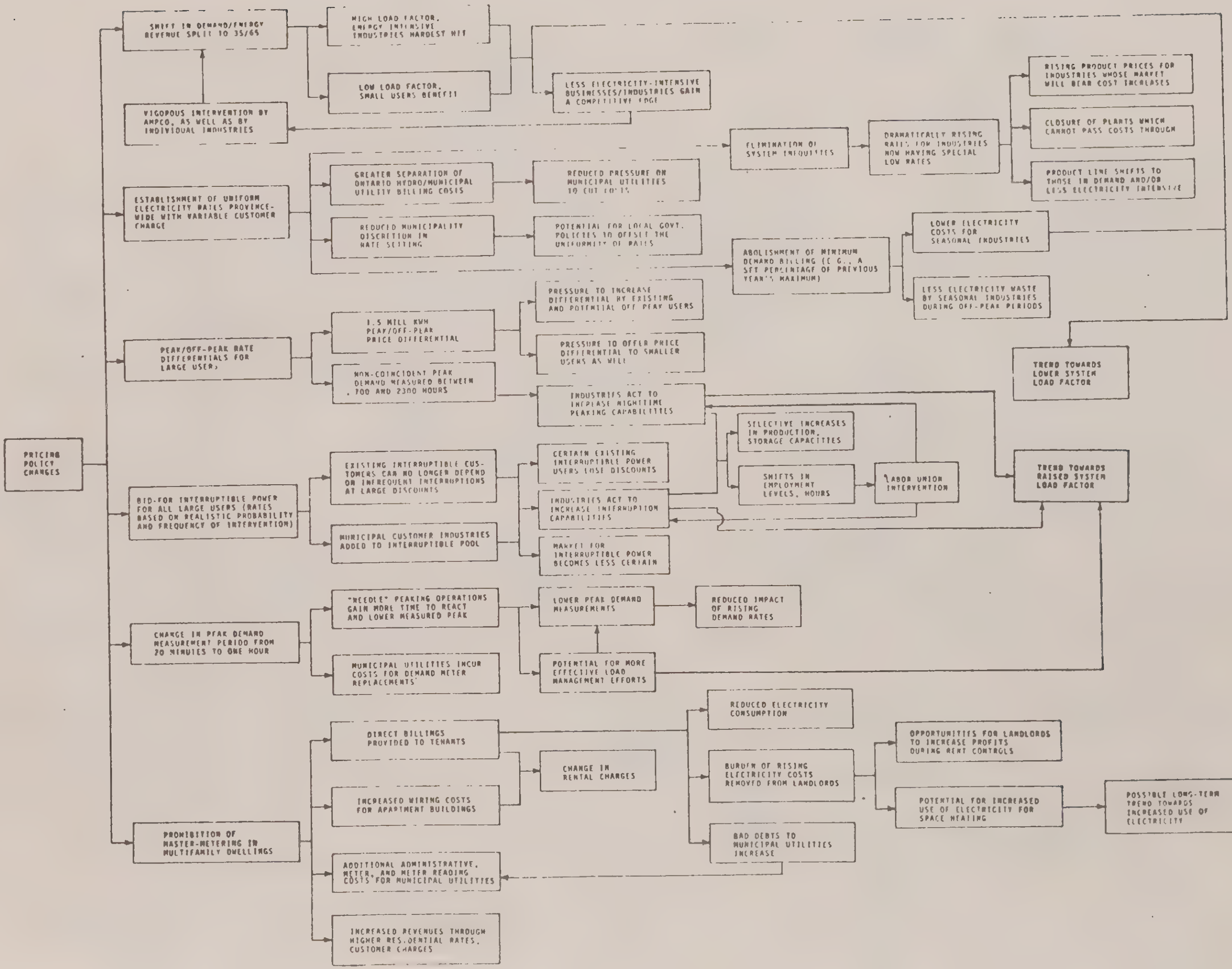


EXHIBIT VIII-3
IMPACT MODEL, PRICING POLICY CHANGES



use power customers starting up in the province identical with these in every way would pay costs about 47 per cent higher for their consumption during the first three years as they would not share in the benefits of historical investment. However, new residential customers would immediately share in the benefits of historical investment, paying exactly the same bills as identical old customers. The greater negative impacts within the general effects are mainly attributable to changes in price levels for electricity (and energy in general) rather than to *marginal-cost* pricing.

2. Long-Run Impacts

In the long run, higher energy costs may lead energy-intensive industries to expand in regions well endowed with low cost energy resources. Alberta has the highest economic growth rate of any province in Canada. During 1976 its disposable income *per capita* surpassed that of Ontario. If one considers that Alberta has no provincial sales tax, one could argue that its residents are already better off than those of Ontario. Shortage of capital for building nuclear plants could aggravate this situation. The implication is that Ontario should plan to restructure its economy towards expanding commerce and service industries that can also serve the other provinces, thereby mitigating the dislocations that could result from no longer being the richest province in Canada. One of the planning-needs easing such a change is to provide a price structure for electricity that will encourage conservation and efficient use. Marginal-cost pricing will serve this need better than average-cost pricing, as various results of the impact study have shown.

3. Impact on Industry

Industry can be expected to offset increases in the price of electricity by using more recycled material and generating more of its own power; Ontario Paper's trash incinerator-generator is an example.

4. Impact on Municipal Utilities and Residential Customers

Municipal utilities are responding to increased costs by considering longer meter-reading periods of half a year or a year. If, in the mean time, customers are billed on an equal-billing basis, their attempts at conservation and efficiency may be frustrated. The residential customer would be especially encouraged in his conservation efforts if his bill each month would reward him. Longer meter-reading periods, and equal billing for the mean time, might work against conservation and efficiency. This situation would be aggravated where water bills were added to electricity bills to provide a single bill to the customer. He might then again be unable to see the fruits of his efforts to save electricity. A printout on the bill showing the previous month's consumption so far during the year, with the corresponding figures for the previous year, would go far to encourage the objectives of conservation and efficiency.

5. Higher-Order Effects

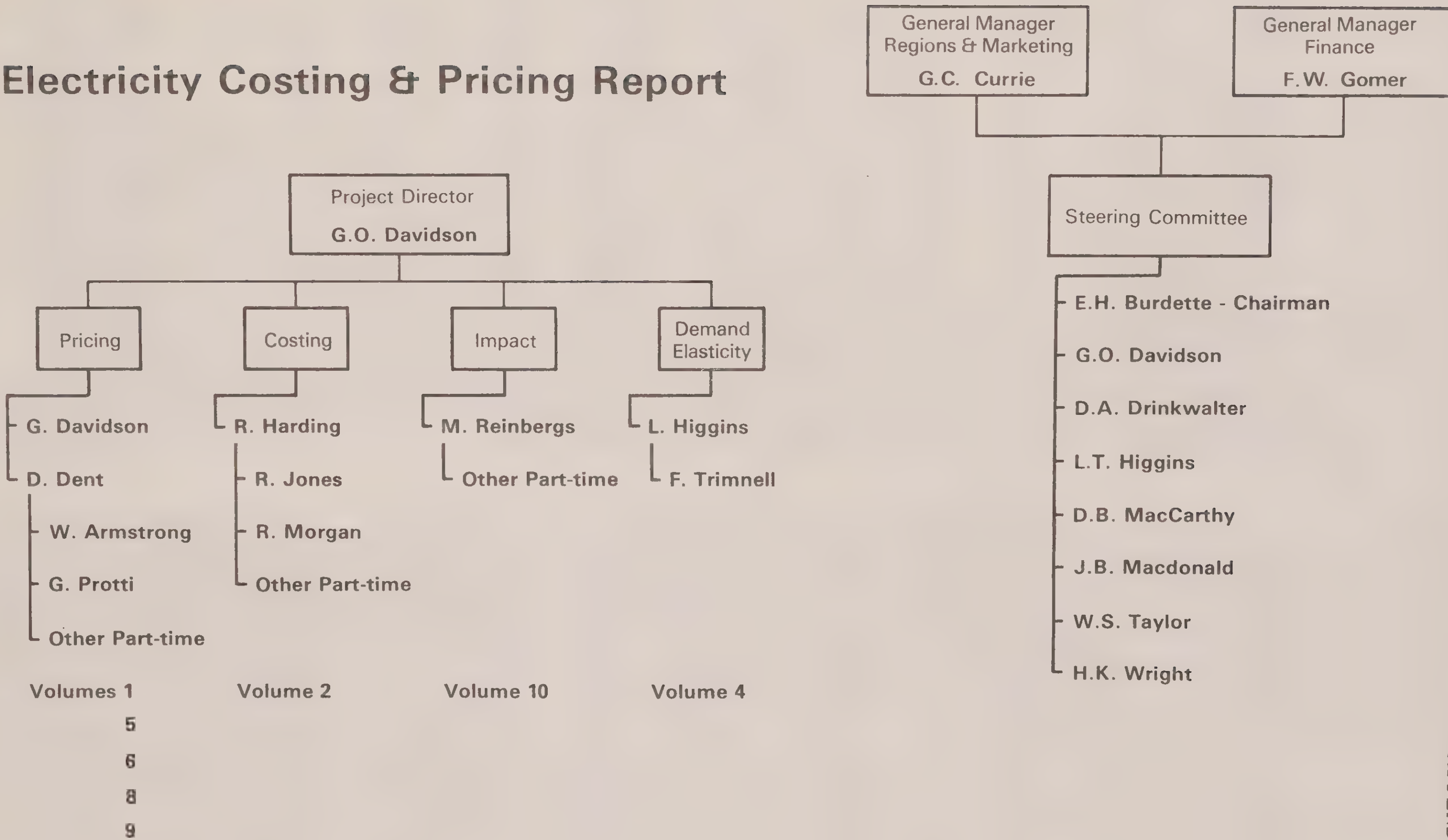
Examples of higher-order effects are:

1. A move back to metering multi-family dwellings individually might lead developers to build all-electric apartments in the future, since (i) individual metering is easier with electricity than with other sources of energy and (ii) landlords would be spared the difficulties of trying to pass through increased energy costs at rent-review hearings;
2. Cement companies located on waterways that allow for lower-cost transport might expand grinding-operations (which are energy intensive) in Quebec, where electricity is cheaper, then ship the clinker to Ontario to complete processing for the Ontario and New York State markets. This, however, would involve a negligible loss of employment.

6. Long-Term Objectives of Impact Analysis

1. Provide management with assessment of the direct and indirect consequences of potential policy changes for both the Corporation and the general public, employing new tools of analysis.
2. Monitor effects as policy changes come into force.
3. Improve the state of the art, especially for quantification and social impacts.
4. Use impact studies as an avenue for interested party input before a project is complete.

Electricity Costing & Pricing Report



Financial Policy Department, Ontario Hydro - Volume 3

Consultants:	NERA	- Volume 7
	NERA	- Volume 4
	Mathewson	- Volume 4
	Hittman	- Volume 10

Secretary to Study Team - K. Zeppa

APPENDIX II: Terms of Reference for Project Team - Electricity Costing and Pricing Studies

In a letter dated 15 October 1974, the Minister of Energy requested Ontario Hydro to identify all study areas recommended by the Ontario Energy Board or studies initiated internally, and to establish priorities for these studies with proposed dates for completion.

In a reply dated 20 November 1974, in commenting on studies relating to costing and pricing of electricity, the Chairman of Ontario Hydro stated that

> *Hydro is undertaking a full scale study of this important subject with a scheduled completion date of February 1976. Following a review of the results by the Energy Board in 1976, we would propose to implement any changes January 1, 1977. This is a difficult study and because of its many facets the staff qualified for carrying it out are those most likely to be actively involved in annual rate hearings, long range planning hearings or other special hearings affecting costs and rates. As mentioned earlier, to assist in preparing these analyses we propose to use consultants where practicable to augment our own staff.*
>
> *Interim studies of certain aspects under this general heading, including a review of the demand/energy rate split, charges for non-common facilities and non-standard rates for such as interruptible service and furnace loads, should be available early next year.*

The foregoing undertakings were entrusted to a steering-committee on the costing and pricing of electricity.

In general terms, the steering-committee's responsibilities were to initiate a review of Ontario Hydro's present costing and pricing practices-and to recommend changes in policies and practices, where warranted.

The steering-committee established four main study areas: namely, pricing, costing, demand elasticity, and impact, integrated into an overall study undertaken by a project team, under the direction of a project director.

Since the four main study areas are not mutually exclusive, there will be a high degree of integration amongst the various areas, in order for the recommendations to be meaningful.

The objective is to study current principles and practices of costing and pricing comprehensively, in order to formulate recommendations for corporate pricing-policies and principles for costing and pricing. These recommendations are to satisfy immediate and long-term aims and objectives within a changing corporate environment.

Terms of reference for these study areas are outlined in schedules A, B, C, and D attached. Each study area is the responsibility of a specific co-ordinator, three of whom are assigned to the project on a full-time basis. The co-ordinators will use internal resources and outside consultants as deemed necessary.

The manner in which the studies have been structured precludes setting criteria for evaluation at this time. However, these will emerge as the studies develop. Criteria for evaluation will be submitted to the steering-committee for confirmation as they become available.

SCHEDULE A: TERMS OF REFERENCE OF THE PRICING-COMMITTEE

1. Subject

The Wholesale and Retail Pricing of Electrical Energy in Ontario.

2. Authority

The General Manager of Finance and the General Manager of Marketing and Regions through the Electricity Costing and Pricing Steering-Committee.

3. Reporting-Responsibility

The Pricing-Study Team Co-ordinator, through the Project Director, to the Electricity Costing and Pricing Steering-Committee.

4. Reporting-Style

The report will be written keeping in mind the requirements of the Board of Directors and the interested public.

5. Purpose of Study

a. Make recommendations for the establishment and approval of corporate pricing-policies for the sale of electrical energy

b. Make recommendations for the establishment and approval of rate structures and pricing-practices, consistent with the aforementioned corporate policies for the sale of electrical energy to (i) municipalities, (ii) customers of the retail system, and (iii) direct customers

c. Make recommendations for the establishment of rate structures and pricing-practices consistent with the aforementioned corporate policies for the resale of electrical energy by municipal utilities to their customers.

6. Scope of Study

a. The Committee will evaluate and make recommendations on alternative pricing-policies and rate structures, having regard to customers, internal costs, governmental policy, and social and economic factors, as well as the impact of these recommendations.

b. The scope of this Committee will include the following studies previously undertaken on an interim basis by other committees.

   i. The examination and assessment of the demand-energy relationships (for the purpose of establishing rates).

   ii. The examination and evaluation of the need for special pricing-policies and structures, such as interruptible power and furnace rates.

c. Committees will examine the pricing-structures used by private companies in Ontario for the sale of electrical energy.

d. The Committee does not intend to examine the pricing-structures used for export power.

e. The Committee does not intend to examine the criteria for revenue requirements.

7. Criteria for Evaluation

Alternative rate structures and pricing-practices will be evaluated on an ongoing basis throughout the study, having due regard for customers, internal costs, governmental policy, and social and economic factors, as well as for technical and administrative efficiency. At present the Committee does not have sufficient information by which to devise specific standards of evaluation.

8. Timing

Because of the commitment made by the Corporation to the Ministry of Energy, the study is to be completed by 31 December 1975. As a consequence of this deadline the pricing-policy recommendations will be completed and submitted to the steering-committee for approval by 30 April 1975. Approval of these recommendations is fundamental to the remainder of the study. It should be noted that a re-evaluation of the division of responsibilities between costing and pricing-committees may be required upon approval of these recommendations.

SCHEDULE B: TERMS OF REFERENCE OF THE COSTING-COMMITTEE

1. Subject

Electricity Cost Determination and Allocation.

2. Authority

The General Manager of Finance and the General Manager of Marketing and Regions through the Electricity Costing and Pricing Steering-Committee.

3. Reporting-Responsibility

The Costing-Study Team Co-ordinator, through the Project Director, to the Electricity Costing and Pricing Steering-Committee.

4. Reporting-Style

The report will be written keeping in mind the requirements of the Board of Directors and the interested public.

5. Purpose of Study

a. Cost Determination

Make recommendations for the establishment and approval of appropriate principles and methods for determining electricity costs.

b. Cost Allocation

Make recommendations for the establishment and approval of appropriate principles and methods for allocating electricity costs.

6. Scope of Study

a. The Committee will analyse alternative methods for determining total costs and their allocation.

b. Methods of determining the electricity costs will include: (i) historical costing, (ii) current-value accounting, and (iii) marginal costing.

c. The effect of social costs will also be considered in the study.

d. Criteria for allocating costs among the customers of the bulk power system will be developed.

e. The method of allocating non-common functions will be based on the results of the recent study on this subject.

7. Criteria for Evaluation

The various principles and methods will be evaluated on an ongoing basis throughout the study. At present the Committee does not have sufficient information by which to devise specific standards of evaluation.

8. Timing

Because of the commitment made by the Corporation to the Ministry of Energy, the study is to be completed by 31 December 1975. As a consequence of this deadline and the requirement to interface with the pricing-study, the cost-determination segment of the study will be completed and submitted to the Steering-Committee by 30 June 1975.

SCHEDULE C: TERMS OF REFERENCE OF THE DEMAND-ELASTICITY COMMITTEE

1. Subject

Response of demand for electricity to changes in its price, the price of competing energy sources, and incomes.

2. Authority

The General Manager of Finance and the General Manager of Marketing and Regions through the Electricity Costing and Pricing Steering-Committee.

3. Reporting-Responsibility

The Demand-Elasticity Study Team Co-ordinator, through the Project Director, to the Electricity Costing and Pricing Steering-Committee.

4. Reporting-Style

The report will be written keeping in mind the requirements of the Board of Directors and the interested public.

5. Purpose of Study

To provide interval estimates of the elasticity of demand for electricity in Ontario with respect to income and price, and of the cross-elasticities with respect to the price of alternative sources of energy.

6. Scope of Study

The Committee will determine interval estimates for price, cross-price, and income elasticities of residential, commercial, and industrial electricity customers in Ontario by means of:

a. the development and application of a comprehensive econometric model for residential and commercial customers;

b. an intensive study of industrial customers' demand; and

c. a critique of studies done elsewhere.

7. Criteria for Evaluation

The results of this study will form an integral part of the concurrent analyses undertaken by the Impact Committee.

SCHEDULE D: TERMS OF REFERENCE OF THE IMPACT COMMITTEE

1. Subject

Impact of Changes in the Costing and Pricing of Electricity.

2. Authority

The General Manager of Finance and the General Manager of Marketing and Regions through the Electricity Costing and Pricing Steering-Committee.

3. Reporting-Responsibility

The Impact Co-ordinator, through the Project Director, to the Electricity Costing and Pricing Steering-Committee.

4. Reporting-Style

The report will be written keeping in mind the requirements of the Board of Directors and the interested public.

5. Purpose of Study

To study the impact on customers and the economy of changes in the costing and pricing of electricity in Ontario.

6. Scope of Study

To determine the theoretical and practical principles and methods for assessing the impact on customers and the socio-economy of changes in costing and pricing in the short and longer term. To provide advice and counsel with respect to impacts of other study teams in the Costing and Pricing Project. To test impacts of the final recommendations of the other studies in the project. To provide recommendations with respect to implementation.

7. Criteria for Evaluation

Current principles and methods of evaluating impact on customers, the environment, and the economy will be examined. Possible new methods and models of impact evaluation that would be compatible with future technology and social environment will be identified. The principles and methods used by other corporations considered leaders in this field will be evaluated. The recommendations should provide the best amalgam or trade-offs among socio-economic, environmental, and customer considerations.

8. Timing

Because of the commitment made by the Corporation to the Minister of Energy, the study is to be completed by 31 December 1975. A discussion paper on the methods under review should be available by 20 June 1975.